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THE COAL FUTURE

APPENDIX H

Medium Btu Coal Gasification

Appendix H

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The Coal Future: Economic and Technological Analysis of Initiatives and Innovations to Secure Fuel Supply Independence

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THE COAL FUTURE

APPENDIX H

Medium Btu Coal Gasification

Contents:

A STEAM PROCESS FOR
COAL GASIFICATION

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NARRATIVE*

The objective of the proposed research project is to develop a medium Btu gasifier which does not require an oxygen plant, does not require any particulate abatement devices to achieve a clean product gas, produces a product gas having a controllable H_2/CO ratio up to 95 percent H_2 (e.g., this ratio can be adjusted for immediate methanation), and does not introduce nitrogen into the gasifier.

The purpose of the proposed research is to develop and carry out a test program to confirm the chemical reactions which occur under the conditions proposed for this gasifier, examine the variation of the products of combustion under the proposed thermodynamic condition, confirm that the gasifier does produce a medium Btu gas, confirm that there are no caking problems under the proposed operating conditions, examine the implications of developing a medium Btu gasifier which contains an adjustable proportion of H_2 and CO, and confirm the adaptability of a pebble bed heater for use in a gasification process.

A review of the most advanced low Btu gasification processes indicates that they are basically air blown systems which produce a gas having a higher heating value below 200 Btu/scf [1-10].** In addition, many of these processes require extensive dust cleaning systems. It has been pointed out in the literature that any enrichment of low Btu gas utilizing O_2 results in a cost penalty of $\$0.20/10^6$ Btu as well as an energy penalty which can be as high as 10 percent of the electrical output of the utility to which gas is being supplied [11-12]. Studies have also shown that low Btu gas utilization is somewhat limited with

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**Numbers in brackets refer to entries in REFERENCES.

heating values below 200 Btu/scf because of pipeline transport limitations.* Gasification installation, having heating values above 300 Btu/scf, however, are able to be transported over sufficiently long distances to allow much greater flexibility. The disadvantages with this medium Btu gas in the past has been the requirement of O_2 enrichment. The process which is proposed is able to supply a medium Btu gas (340 Btu/scf) without requiring O_2 enrichment. Further, there is no need for any dust control apparatus in the system. The gas leaving the gasification system is virtually dust free. Finally, the H_2/CO ratio in the product gas is completely variable for the proposed process. In fact, by operating at high pressures, the shift conversion step can be bypassed if a high Btu gas is desired. The process can also be run under operating conditions in which no char is produced without the addition of oxygen.

A summary of the advantages and disadvantages for the proposed system is given below.

Advantages:

1. Since coal is never burned, the system can be designed to handle coal with ash having a low fusion point by controlling the maximum temperature in the gasifier.
2. There is no nitrogen introduced into the reactor and hence there is no need to use pure oxygen to achieve a medium Btu product gas. This condition results because steam is used both as a reactant and as a heat source in the reactor.

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3. There is no inherent char formation in the proposed system* because of the amount of excess steam used in the reactor.
4. The fuel gas composition of the CO/H_2 ratio can be varied either in the initial design or during operation to suit subsequent process needs, such as methanation, methanol production, or hydrogenation.
5. The H_2 produced is saturated with water vapor which prevents embrittlement of steel.
6. When no external heat source is used in the auxiliary boiler, there is no air pollution from the process. Fine fly ash products are removed with the condensate. Only water treatment and water cooling is required.
7. This coal gasification system can incorporate solid waste efficiently. When this is done, air pollution control of the combustion products of the solid waste in the boiler might be needed.
8. For high sulfur coal, the use of excess H_2O assures the formation of H_2S (with the amount of COS formation being negligible). If the H_2S produced from using coal having a 5 percent sulfur content is treated to produce elemental sulfur and H_2, this H_2 can be recycled in the process to be used as part of the fuel gas. For this example, the H_2 produced from the sulfur process amounts to about 2 percent of the total H_2 in the gas.

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9. The higher heating value of the fuel gas can be realizable in* some applications since the fuel gas does not cause acid corrosion because sulfur is removed in the process.

10. Gas is produced with an overall system efficiency of 60 to 70 percent without N_2 dilution or use of pure O_2.

11. Coal with a low fusion temperature of ash (Illinois coal has a softening temperature between 2,250°F and 2,520°F with an average of 2,360°F) can be handled in the present system. Options of reactor configurations for the proposed process include:

    a. Fixed bed--can be designed for operation at temperatures below that of ash fusion,

    b. Fluidized bed--can be designed for temperatures below that of ash fusion (gas bubbles in the fluidized bed are not as detrimental as in gasification processes using oxygen or air where short circuited oxygen will burn with the fuel gas leaving the bed),

    c. Spouting bed--for high temperature operation with slag removal, and

    d. Cyclone entrained bed--at high temperature and slag removal.

12. Unless the tar is removed by preheating at a low temperature (930°F), the tar in the coal is reduced to CO and H_2.

13. The 1 percent nitrogen found in the coal is either in an adsorbed or in a combined form such as CN and hydrides. These

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compounds will be reduced at the reactor condition to N_2 gas*
or NO (the latter being readily removed by dissolving in the condensate).

14. A high system pressure is desirable because the power consumption to pump water is less than that for compressing the gas produced for transmission and/or storage.

Disadvantages:

1. The CO_2 in the raw fuel gas needs to be removed, although the MEA CO_2 absorption process is commercially available. This is a problem common to most gasification processes.
2. Reactor steam injection rates five times greater than those used in current design may be required. All of this water is not consumed, however. Approximately 40 to 50 percent more water may be consumed with this process under the worst case conditions. In addition to the water injected into the reactor, cooling water is also needed.
3. The pebble or refractory heater operating at high temperature with pebbles or parts undergoing alternate heating and cooling will have similar problems as in its applications in petroleum refineries. These refractory heaters are widely used in the petroleum industry.
4. The existence of a lower heating value is a result of the hydrogen in the fuel gas. This heating value depends on the H_2/CO ratio as in other gasification processes.

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5. For the same transmission pressure and pressure drop over a* given distance, the present fuel gas calls for a 50 percent greater pipe diameter than methane. It should be noted, however, that the medium Btu gas produced in this process is ready for methanation.

The validity of the steam process of gasification is explored, in a preliminary way, in the studies of Jensen [13] and of Oppelt, et al.,[14]. Both of these studies used electrical heating.

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PROCESS DESCRIPTION

Overview

The present process gasifies coal by reacting it with steam at* temperatures of 2,000 to 3,000°F or higher without the coal ever coming into contact with air or oxygen. Indirect heating of the steam entering the reactor is accomplished using a pebble bed heater which utilizes a recycled fraction of the gas produced for heating the bed. Stack emissions from the boiler and heater are as clean as any gas fired system. Since excess steam is used both for heating as well as for gasifying the coal, the sulfur in the coal is removed in a liquid solution. As a typical example, a 550 tons per day plant operating at a moderate pressure of 220 psi with a maximum steam temperature of 3,000°F, an estimated overall system efficiency around 70 percent is attainable for producing a net of 15,700 scfm of gas at 340 Btu/scf. If provision is made for stack gas treatment and solid waste is burned in the auxiliary boiler part of the system, the system efficiency can be raised up to 86 percent with a 25,700 scfm output.

A description of the major elements of the proposed process operating in a steady flow state is given below. The system can also be operated as a batch process (see APPENDIX A).

The compressed air from compressor c (28), after passing through the heat exchanger (29a),is fed through a nozzle into the riser to lift the pebbles from the regenerator section (11b) into a cyclone which separates the pebbles feeding the pebble regenerator in section (11a) from the air. The air is then directed into the burner (14) which

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produces a hot gas by burning a fraction of the recycled product fuel gas* to raise the pebbles (say, 0.5 inch mullite) to 3,500°F while the hot gas is cooled to 1,200°F and fed into turbine (T1). The heated pebbles pass on through a throat which also serves as a gas seal into section (11b) where superheated steam at 1,200°F is heated to 3,000°F. The design pressure, for illustrative purposes, is 220 psi. Leakage of either hot gas or steam is controlled by adjusting the pressures in (11a) and (11b).

Steam heated to 3,000°F is fed into a spouted bed of coal in the gasifier (19) while coal is delivered under pressure. The air is taken into a turbine (T2) which recovers the power by driving a generator or drives an air blower to furnish additional air if needed in boiler (6); the air from the turbine (T2) is near atmospheric for the boiler (6). Depending on the properties of the coal supplied, the gasifier (19) shown in Fig. 1 can still be used. Other alternate reactors such as a conventional fluidized bed could also be used in (19). Additional details are given in APPENDIX A.

The system shown in Fig. 2 describes typical operating parameters for a capacity of 550 tons per day of coal, although it would be feasible to design a system capable of handling up to 10 to 20 times this amount of coal. While a 220 psi maximum pressure is used for illustration, the system can be designed to operate near atmospheric pressure; the simplification would involve the elimination of the turbine-compressor. A motor-driven blower would be sufficient for this latter configuration.

The novel features of the proposed process include reacting coal with superheated steam under conditions of high excess steam and utilizing

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a pebble bed configuration to preheat the steam before entering the re-* actor. The bed configuration is novel in that the pebbles are heated by combusting a fraction of the recycled gas produced with air in one section of the pebble bed which is isolated from the steam heating section. The ability to control the steam temperature entering the reactor allows for a variable H_2/CO ratio in the product gas. The ability to superheat the steam in the absence of air to high temperatures and to control the amount entering the reactor removes the necessity of an oxygen plant to achieve medium Btu gas. The use of gas to heat the pebble bed avoids spalling of pebbles by particulates.

The major components of the system are available within current engineering practice. These include turbine-compressor sets, pebble bed regenerator, risers, cyclones, spouted beds, pack beds, or fluidized beds, boilers, and heat exchangers. Since H_2S is produced instead of SO_2, sulfur is readily removed. The arrangement of these components as well as the operating conditions are believed to be novel.

The feasibility of the process using excess steam can be demonstrated by examining the reactions under equilibrium conditions. To generate H_2 at 1,800°F, using stoichiometric amounts of H_2O, steam has to be heated to above 16,000°F. Because the present invention uses excess amounts of H_2O as a heat transfer fluid, steam supplied at 2,500°F is sufficient to furnish the needed heat of reaction. This excess H_2O also displaces the chemical equilibrium to a point favoring the formation of H_2S instead of SO_2 which is also desirable.

Figure 2 is a diagrammatic representation of the proposed system.

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A gas-fired pebble bed heater (or other form of ceramic heater such as* Rhote Muehle-B. and W. Company system) heats the steam from T_s as delivered from the boiler-superheater to T_r. This steam is used to both heat and gasify the coal in the reactor. The gas produced together with the excess steam at T_e enters the cooler in which the gas is quenched and steam is condensed while heating the water, steam, and air for combustion. The output gas containing principally H_2, CO, CO_2, and H_2S, passes through absorbers to remove sulfur and CO_2 to produce a fuel gas having a higher heating value of 340 Btu/scf independent of the proportion of CO in the gas. The heat absorbed is determined by the heat of reaction and equilibrium based on the data in Table 1 (Basic Reactions), the specific heat of the coal and the composition of its ash. It is seen from Reaction (2) that 3,235 Btu/lb - C is absorbed or 970 Btu/lb H_2 is produced from the C. Reactions (7) and (8) show 932 Btu/lb S absorbed from the pyrite reactions or 14,940 Btu/lb H_2 from the S. Hence, for a coal of 95 percent C and 5 percent S, 3,120 Btu/lb fuel will be absorbed. This figure is increased by the formation of CO in Reaction (1), as well as by the decomposition of sulfates and carbonates in the ash. Reactions (1) and (2), in Table 1, are, in effect, the utilization of C to reduce H_2O. Since, in the present process, this is the only objective in the reactor, this process affords great flexibility in determining the proportions of H_2 and CO in the gas produced. Most conventional gasification processes try to both supply heat by combustion and accomplish this reducing process at the same time in the reactor. As a result, the ratio of H_2 to CO is much lower than for the proposed process. APPENDIX A includes the patent application of

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S. L. Soo of the high-pressure burningless water gas process of coal gasification, on which the present proposal is based. While no decision has yet been reached as to the status of its patent, the information presented here and in the appendices is proprietary. APPENDIX C is a signed copy of provisions of the DISCLOSURE SUBMISSION CONDITIONS.*

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SYSTEM PARAMETERS

The Q's in Fig. 2 denote the heat transferred at each element of* the process; the W's denote work input, all for 1 lb-mole of H_2O into the reactor. A range of design and operating conditions showing the influence of variables in different cases for the system in Fig. 2 is given in Table 2. Table 2 also shows the range of choice of composition of fuel gas produced via proper selection of design parameters. The column entitled "Typical Laboratory Experiment" gives data of the proposed laboratory work showing its usefulness in demonstrating the validity of the system in Fig. 1.

The data in Table 2 are grouped under design parameters, energy relations, flow quantities, product compositions, and performance parameters. Cases illustrated show the flexibility of the design of the system to cover a wide range of situations. Calculations were based on heat of reactions and chemical equilibria as given in Table 1. Flow relations in Table 2 correspond to the diagram in Fig. 1. The items in Table 2 are further noted as follows:

Item 1: Carbon input C** is that reacted with 1 lb-mole of H_2O. For T** tons per day of 12,000 Btu/lb coal, multiply extensive quantities in table by 0.0985 T**/C** to obtain per minute values. Case (6) shows that the system can be designed to handle low fusion temperature ash in a fluidized reaction.

Item 2: Maximum temperature is that at the inlet to the reactor as produced by the pebble heater. The steam is supplied

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**Decomposition of sulfates and carbonates in ash absorbs additional amount of heat.

as a heat source as well as a reactant. A greater amount* of heat or steam may be needed depending on properties of ash** in coal.

Item 3: Quenching temperature is that leaving the reactor into the cooler where rapid cooling will lead to frozen equilibrium condition. The fuel gas composition can be modulated by this temperature and carbon input, (Items 16 and 17).

Item 4: The system pressure of 10 atm has been chosen for those equilibria where soot or char formation occurs at much higher pressures (allowable pressures in parenthesis). For Cases 5 and 6, the pressures were determined from the condition where no carbon is left in the product. Hence, the system can be designed for no carbon left-over while satisfying other conditions. Where there is no excess of H_2O such as in several conventional gasification systems, the case of no carbon left-over occurs only at zero pressure or at excess O_2.

Item 5: H_2O converted by equilibrium reactions of different cases are given. One (1) minus this amount is eventually condensed and recycled, except approximately 1 percent of water vapor remains with the product gas as saturdated vapor. Hydrogen in the product gas does not cause embrittlement of steel when it is saturated with water vapor. In the condensor, flyash carried over serves as condensation nuclei and will not cause air pollution.

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**Decomposition of sulfates and carbonates in ash absorbs additional amount of heat.

Item 6
and
Item 7: Ninety percent heat exchanger effectiveness was taken,* which is attainable within economical designs.

Item 8: The heat to cooling water is the net condenser heat removal. Cooling water requirement is determined from this item. Note that high maximum steam temperature and low quenching temperature means a more efficient system and lower cooling water demand or thermal pollution. Fine flyash, forming condensation nuclei, is removed with the condensate.

Item 9: The pump work shows that it is economical to pump water to generate steam at the desired gas supply pressure than to pump the gas.

Item 10: The blower work for pumping the air required in combustion was calculated for the intermittent heating system of the pebble heater and an air pressure of 30 inches water would be sufficient. For the steady flow system, air at the system pressure can be produced with a turbo-compressor unit, with the turbine recovering the larger part of the compressor work and no significantly greater net work input is expected.

Item 11: The fraction of gas produced is burned with air to heat the pebble heater. Hence, the pebble or refractory heater is never exposed to carbon or coal, thus avoiding spalling

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of the pebbles by the soot particles and erosion by the* slag. Note that higher maximum steam temperature means greater demand in the pebble heater; this is because a superheater outlet of 1,200°F has been chosen according to current engineering practice. Higher superheater outlet temperature will reduce this demand.

Item 12: The fraction of gas to the boiler, if used, will eliminate air pollution completely. The only environment impact will be treatment of recycled water and supply of make-up water for the process and the cooling water regeneration. If, as is noted with Item 7, external source of heat is used, such as solid waste, the gasification efficiency will be greatly improved. As a matter of fact, this system is the only one which effectively converts solid waste to fuel gas, as noted in Item 27 (for system with low maximum temperature) as much as 30 percent of the heat needed in gasification can be supplied from solid waste.

Item 13: The number of moles air for combustion in Items 6 and 7 for each case is given. The air is preheated in the cooler and in heat exchangers recovering heat from the combustion product leaving the heater and the boiler. Note that even though air instead of oxygen is used in this gasification process, there is no nitrogen dilution of the fuel gas.

Item 14 and Item 15: The greater efficiency of greater T_r and lower T_c is seen in the greater amount of fuel gas produced by given carbon input.

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Item 16
and
Item 17: The process can be adjusted to produce a gas of desired* proportion of CO and H_2. Case 1 or nearly 3 to 1 H_2 and CO is desirable for methanation. Still higher CO can be used for producing methanol. Higher percentage of H_2 than Case 6 can produced for hydrogen fuel systems, or hydrogenation.

Item 18: Moles of CO_2 to be absorbed may be considered a disadvantage of the system. The process is, however, routine; one of these is the MEA (mono-ethanol amine) system.

Item 19
and
Item 20: Calculations from equilibria of H_2S show an important advantage of the present system: Because of excess of H_2O and H_2, SO_2 (such as from sulfates in the ash) (less than 10^{-7} of H_2S) and COS (less than 1/100 of H_2S) are both negligible in the gasification product; the H_2S is readily removed in such as the Girbotol or Stretford processes with recovery of H_2 to the fuel gas. In another way of speaking, S in coal (also in pyrite form) also contributes to the production of H_2 (see Table 1).

Item 21
and
Item 22: The higher heating value (HHV) and the lower heating value (LHV) of the final fuel gas is given. The LHV is applicable to usages where H_2O from combustion is not condensed. The difference is nearly 45 Btu/scf, even when 90 percent of H_2 and 10 percent of CO is produced. Note also that HHV is at least in part realizable in boilers because acid corrosion is no longer a concern.

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Item 23
and
Item 24: The efficiency range shows that the efficiency is comparable or better than those reported. Even the efficiencies based on LHV are competitive. Note the Case 6 where an efficiency of 67 percent was obtained with 30 percent of heat from solid waste and 70 percent of the heat from coal of high sulfur, low fusion ash. Neither can be handled in other gasification processes. The LHV efficiency would be 95.8 percent if solid waste is available at zero cost, and better yet if the system is credited for waste disposal.

The general feature of the present process is seen in the chemical equilibria of C and H_2O at various temperatures and pressures. For the water gas reactions (1) and (3) of 1 mole of C and a_o mole of H_2O at equilibrium, we have:

$$C + a_o H_2O \rightarrow a_1 CO + (1 - a_1 - a_5) CO_2 + (2 - a_1 - 2a_5) H_2$$
$$+ (a_o + a_1 + 2a_5 - 2) H_2O + a_5 C$$

with a_5 mole of C in the form of soot or char. The relations for various a_o and temperature and pressures are shown in Fig. 3. It is seen that for $a_o \leq 1$, which is the case of several conventional gasification processes, $a_5 = 0$ occurs at only zero pressure. Take the case of quenching of a gas from $a_o = 1$ at 1200°K (1740°F) at 10 atm, $a_5 = 0.1$ mole of C will be left. For Case 2 of Table 2, however, $a_o = 5$, soot formation occurs only at very high pressures. For these two values of a_o, we have the following comparisons for 10 atm pressure, based on 1 mole of C:

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Quenching	Conventional Process Point B in Fig. 2 1740°F	Present Process Point A in Fig. 2 1120°F
H_2O in (a_o)	1 mole	5 moles
Product Moles		
C (soot, char)	0.1**	0
H_2O	0.02	3.2
CO_2	0.09	0.8
CO^2	0.82	0.2
H_2	0.98	1.8
Fuel Gas		
CO	45.5 percent or higher*	10
H_2	54.5 percent or lower	90
Sulfur n_{H_2S}/n_{COS}	38	250

Hence, the present process may give a fuel gas of 10 percent CO and 90 percent H_2 or 25 percent CO and 75 percent H_2 in case 1, Table 2, without the dilution by nitrogen even though air is used in the heat generation. Moreover, excess supply of steam eliminates char formation.

*Because air or oxygen will be present in the original input to produce the heat of reaction.

**Except when oxygen is in excess.

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Plant Design and Operation

While different cases in Table 2 may be regarded as illustrating the consequence of selecting different design parameters, they also illustrate the range of operation and adjustment with the input variables such as coal composition, availability of solid waste, and the desired fuel gas composition.

Table 3 illustrates two typical design conditions for a gasification plant of an output of 18,000 scfm gas of 340 Btu/scf HHV. The fuel supply is 500 tons per day of coal as specified in the case (A) and 330 tons per day of coal and 281 tons per day of solid waste in the other (B). Another view of this table is that it gives the operating conditions of a given gasification plant at two different fuel supply conditions. Note that 5 percent of S in the coal may produce an additional 2 percent of the fuel gas.

PROPOSED STUDY

The proposed study consists of two phases. Phase 1 includes the* verification of the process as a viable means for gasification, a detailed gas and condensate analysis and the determination of design parameters for a gasification plant (Table 4). This will be conducted in the Mechanical Engineering Laboratory on bench scale equipment with available steam supply and electric heating. Reference tests will be made with carbon for the comparison of a wide range of coal samples. A preliminary design of a pilot plant is in Phase 2.

Phase 1: Work in this stage will be conducted over a period of 12 months. For conducting the tests, the 150 psig gasification system shown in Fig. 5 is to be constructed. A schematic of this system is shown in Fig. 4. Available steam supply in the Mechanical Engineering Laboratory at 150 psi and 375°F will be connected to the experimental setup via 2-inch valve on the steam main. The steam, after passing through a reducing valve, will be heated in an available electric heater powered by a 20 kw dc power supply. As shown in Fig. 5, the desirable steam temperature is obtained by mixing of the streams at high and low temperatures. For tests with 3,000°F steam for the reactor, a flow of 0.75 lb per minute can be maintained. The refractory (magnesia brick) lined reactor contains a bottom layer of spheres of mullite (limited to 3,340°F) or other refractories (such as fused magnesia for up to 4,000°F) for distributing the steam flow into the coal bed of lump coal or coal dust for fluidized bed tests. These refractory spheres will be 0.5 inches in diameter or 0.25 inches in diameter for obtaining knowledge

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of the heating and cooling characteristics of these refractory spheres.* The flow velocities will be below 5 fps. The charge of 6 to 10 lbs of carbon or coal will permit a running time of about one hour. The temperature will be monitored by thermocouples (TC) located at various points. The operating pressure of the reactor is reduced to slightly above atmospheric pressure such that the gas delivered is nearly atmospheric for analysis. Adjustments will be made for various outlet temperatures T_e for quenching and cooling. The condition inside the reactor will be observed through view ports. The gas flow will be measured by a wet test meter and its heating value will be determined with a Junkers calorimeter. The reference test will be that made on laboratory grade charcoal chips. Tests and adjustments and corrections will be made to reach a lower heating value of above 200 Btu/scf (CO_2 is not removed in this stage). From that point on, coal samples will be tested for the ability to achieve a heating value of such a magnitude. These results will determine whether the program will proceed any further.

The acquisition of chromatograph will be for gas analysis and the cooling needs will be determined by weighing the cooling water flow. Reaction rates will be determined by different running time and different sizes of batches. Optimum temperatures of inlet steam (T_r) and outlet gas (T_e) will enable us to reevaluate the proposed system and its design conditions.

Determination will be made on the reaction rate, heat transfer relations for the desired quenching conditions, condenser operation, and ash and condensate analyses. Batch testing will still be necessary and extensive coal and ash analyses will be performed. The apparatus shown

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in Fig. 5 may develop a standard tool for evaluating coal for the present* process of gasification. This stage will evolve into a continuing laboratory function of control tests for pilot plant reference and coal process evaluation.

Phase 2: Based on the design information obtained above, design of the pilot demonstration plant will be made. Further tests will include using the gas produced in Phase 1 equipment to test the pebble bed, the effect of thermal cycling of the pebbles of mullite or magnesia (for both periodic system and steady flow system), and component needs. Coal lock and coal feed systems and ash lock and ash disposal systems will be designed and specified. Design will also be made on the H_2S and CO_2 absorption system. A proposal for a pilot or demonstration plant will be completed in this period for beginning of installation by mid-1976. Table 4 is an outline of the proposed time schedule and shows overlapping of stages and phases. The present proposal covers Phase 1 and the design stage of Phase 2.

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14. Oppelt, W. H., Kamps, T. W., Gronhovd, C. H., Kube, W. R., and McMurtric, R., "Production of Crude Ammonia-Synthesis Gas from North Dakota Lignite in Annular-Retort Gasifier," U. S. Bureau of Mines Report No. 5297 (1957).

Table 1 Basic Reactions (Multiply kcal/g-Mole by 1,800 to get Btu/lb-Mole) and Equilibrium Constants between 800°K and 1,200°K

Gasification:

(1) $C + H_2O_{(g)} \rightleftarrows CO + H_2 + 31.398$ kcal/g-Mole

$$\log_{10} K_1 = \log_{10} (P_{CO}\, P_{H_2}/P_{H_2O}) = 7.641 - 7{,}230/T_{(°K)}$$

(2) $C + 2H_2O_{(g)} \rightleftarrows CO_2 + 2H_2 + 21.57$

(3) $CO + H_2O_{(g)} \rightleftarrows H_2 + CO_2 - 9.828$

$$\log_{10} K = \log_{10} (P_{H_2}\, P_{CO_2}/P_{CO}\, P_{H_2O}) = -1.791 + 1{,}872/T_{(°K)}$$

Combustion:

(4) $C + O_2 \rightleftarrows CO_2 - 94.052$

(5) $CO + O_2 \rightleftarrows CO_2 - 67.636$

(6) $H_2 + \frac{1}{2} O_2 \rightleftarrows H_2O_{(\ell)} - 68.315$

$\rightleftarrows H_2O_{(g)} - 57.798$

Sulfur:

(7) $H_2S \rightleftarrows H_2 + S + 4.8$

(8) $FeS + H_2O_{(g)} \rightleftarrows FeO + H_2S + 11.8$

(9) $3H_2 + SO_2 \rightleftarrows H_2S + 2H_2O_{(g)} - 49.48$

$$\log_{10} K_S = \log_{10} (P_{H_2S}\, P_{H_2O}^{\;2}/P_{SO_2}\, P_{H_2}^{\;3}) = -4.543 + 11{,}700/T_{(°K)}$$

(10) $CO + H_2S \rightleftarrows COS + H_2 - 35$

$$K_{COS} = P_{COS}\, P_{H_2}/P_{CO}\, P_{H_2S} \simeq 0.0316$$

Table 2 Summary of Product and Energy Relations of Process (based on 1 lb-Mole of Steam at Reactor Inlet, 1,200°F at Superheater Outlet (T_s), 100°F Condenser Temperature (T_c))

Cases	1	2	3	4	5	6	Typical Laboratory Experiment
Design Parameters:							
(1) Carbon Input, C^*, lb-Mole	0.35	0.35	0.30	0.25	0.30	0.25	0.35
(2) Maximum Temperature, T_r, °F	3240	3000	2750	2500	2510	2270	3000
(3) Quenching Temperature, T_e, °F	1500	1300	1300	1300	1100	1100	1300
(4) System Pressure, P, atm	10	10	10	10	3	6	1-10
(Allowable)	(70)	(12)	(23)	(27)	(3)	(6)	
(5) H_2O Converted, lb-Mole	0.519	0.548	0.487	0.421	0.516	0.444	0.55
Energy Relations:							
(6) Heat to Pebble Heater (90% Effectiveness) Q_H, 10^3 Btu	25.20	21.97	18.63	15.41	15.53	12.50	30 Electric Heater
*(7) Net Heat to Boiler (90% Effectiveness) Q_{ba}, 10^3 Btu	12.39	14.98	15.23	15.49	17.83	18.01	Steam Supplied
(8) Heat to Cooling Water, Q_w, 10^3 Btu	6.46	5.94	6.98	8.10	6.51	7.73	21.6
(9) Pump Work, w_p, Btu	7	7	7	7	2	4	--
(10) Blower Work, $w_?$, Btu (30 inch H_2O equivalent)	28	27	25	23	8	14	--
Flow Quantities:							
(11) Fraction of Gas to Pebble Heater	0.332	0.291	0.287	0.289	0.243	0.236	--
(12) Fraction of Gas to Boiler*	0.163	0.193	0.236	0.290	0.279	0.340	--
(13) Moles of Air	0.824	0.815	0.750	0.688	0.746	0.685	--
(14) Moles Fuel Gas Generated	0.354	0.358	0.286	0.211	0.287	0.212	0.7
(15) Moles Fuel Gas (Generated with External Heat)	(0.468)	(0.496)	(0.428)	(0.356)	(0.454)	(0.382)	--
Product Compositions:							
(16) Fuel Gas: CO, %	25.8	21.7	18:8	15.8	11.2	11.2	22
(17) Fuel Gas: H_2, %	74.2	78.3	81.2	84.2	88.8	88.8	78
(18) Moles CO_2 to be Absorbed	0.196	0.198	0.187	0.171	0.216	0.194	Not Removed
(19) $N_{H_2S}/N_{SO_2} \cdot 10^7$	0.712	15.9	9.03	4.76	403	202	
(20) N_{H_2S}/N_{COS}	91	114	137	169	195	250	
Performance Parameters:							
(21) Higher Heating Value (HHV, Btu/scf)	342	342	342	342	342	342	266
**(22) Lower Heating Value (LHV), Btu/scf	303	301	299	298	297	295	234
(23) Efficiency, HHV (without External Heat), %	73.3	74.1	69.2	61.2	69.4	61.7	--
*(24) Efficiency, HHV (with External Heat), %	80.2	92.7	79.6	75.6	81.3	77.9	96(3)
(25) Efficiency, LHV (without External Heat), %	64.9	65.2	60.5	53.2	60.2	53.2	--
*(26) Efficiency, LHV (with External Heat), %	71.0	81.5	69.6	65.8	70.5	67.2	85(3)
*(27) % Waste Heat Utilizable	17.3	20.2	23.1	26.8	26.0	29.9	--

For T* Tons of Coal per Day of 12,000 Btu/lb, Multiply Extensive Quantities by 0.0285 T*/C* to obtain Moles per Minute.

*May use external heat source such as solid waste; (3) External Heat Not Charged.

Table 3 Typical Design Conditions for 18,000 scfm Gas of 340 Btu/scf (HHV)

A. Coal Gasification (Air Pollution Control not Needed)
(Corresponding to Case (1) of Table 2)

Fuel:	500 Tons/Day of Coal of 12,000 Btu/lb 9% Ash; 5% Sulfur
Gas Produced:	25% CO, 75% H_2
Water:	158 gpm Converted
	146 gpm Treated and Recycled
	3,700 gpm Cooling Water (30°F Temp. Rise)
Air:	41,620 scfm, 93 hp Net
Pebble Heater:	2.13×10^8 Btu/hr, 11,700 scfm Fuel Gas
Boiler:	1.03×10^8 Btu/hr, 5,760 scfm Fuel Gas
Raw Gas Treatment:	CO_2 Removed: 9,900 scfm
	H_2S Removed: 330 scfm
	Giving: 21 Tons Sulfur/Day 330 scfm H_2
Efficiency:	73% (HHV), 65% (LHV)

B. Coal Gasification with Burning of Solid Waste which May Need Air Pollution Control (Corresponding to Case (6) of Table 2)

Fuel:	330 Tons/Day of Coal of 12,000 Btu/lb 9% Ash, 5% Sulfur
	281 Tons/Day of Solid Waste of 6,000 Btu/lb
Gas Produced:	11% CO, 89% H_2
Water:	125 gpm Converted
	156 gpm Treated and Recycled
	4,000 gpm Cooling Water (30°F Temp. Rise)
Air:	32,000 scfm, 43 hp Net
Pebble Heater:	10^8 Btu/hr, 8,350 scfm Fuel Gas
Boiler:	1.41×10^8 Btu/hr, Heat from Solid Waste Burning
Raw Gas Treatment:	CO_2 Removed: 9,100 scfm
	H_2S Removed: 219 scfm
	Giving: 14 Tons Sulfur/Day 220 scfm H_2
Efficiency:	78% (HHV), 67% (LHV)

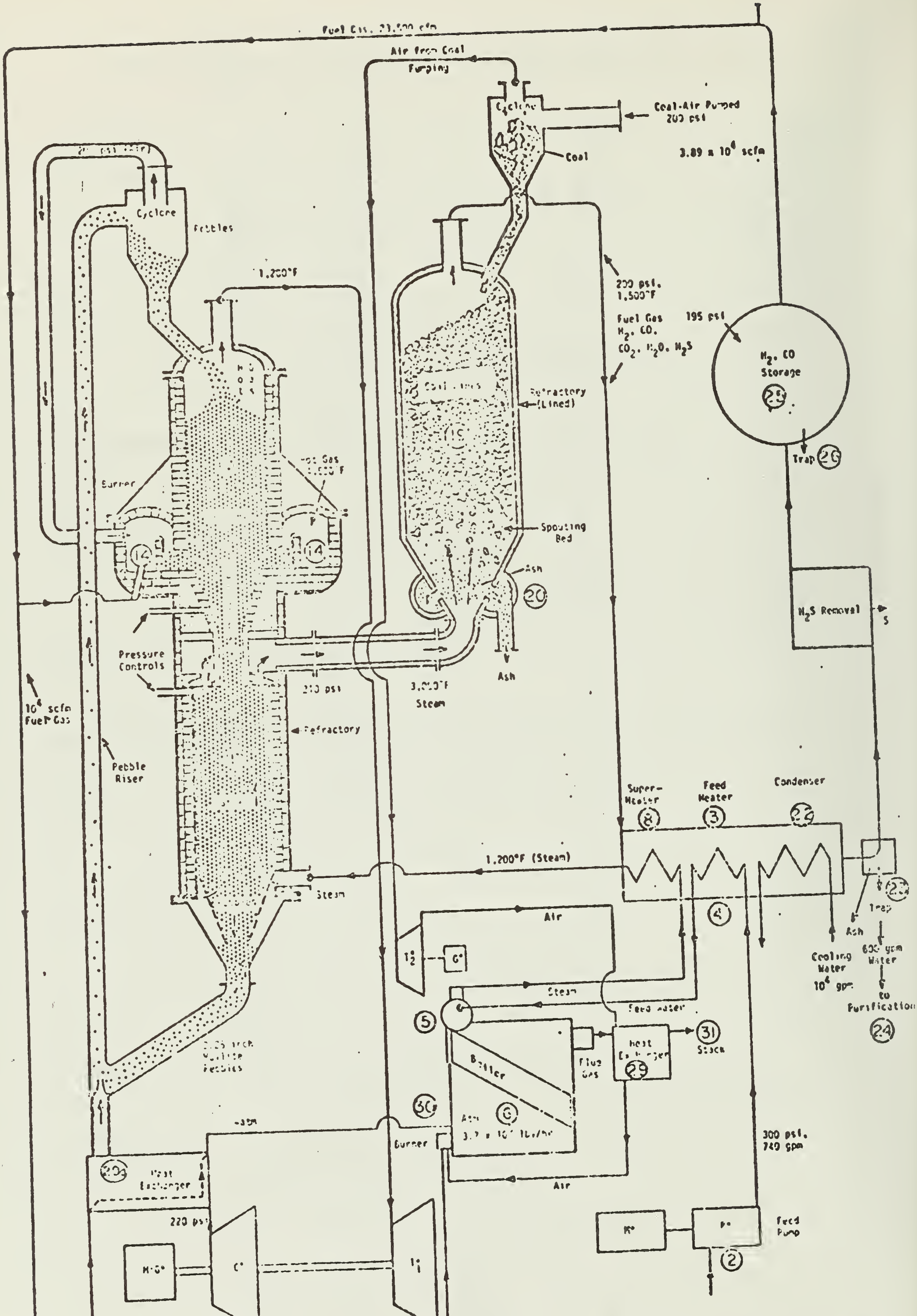
Table 4 Time Schedule for Proposed Program

```
           1975 ---------------->|<----------- 1976 ------------------>|<---- 1977 ----->|
            6  7  8  9 10 11 12  1  2  3  4  5  6  7  8  9 10 11 12  1  2  3  4  5  6

Phase 1    |<------------------------------------->|<------------------------------------>|
            (Tests for System Parameters)           (Continuing activity of control tests
                                                     and coal process evaluation)
                                                                                          Preser
                                                                                          Proposa
Phase 2
Stage 3                   |<------------------------------->|
                                     (Design)

Phase 2                        |<--------------->|<---------------------------------------->|
                                 Pilot Plant            (Plant Installation)
                                 Proposal in

Phase 3                                                           |<---------------->|
                                                                   (Testin, 2 yrs)
```



LEGEND
MG denotes motor-generator; T, turbine for power recovery; C, compressor
(Start)(running)-condition)

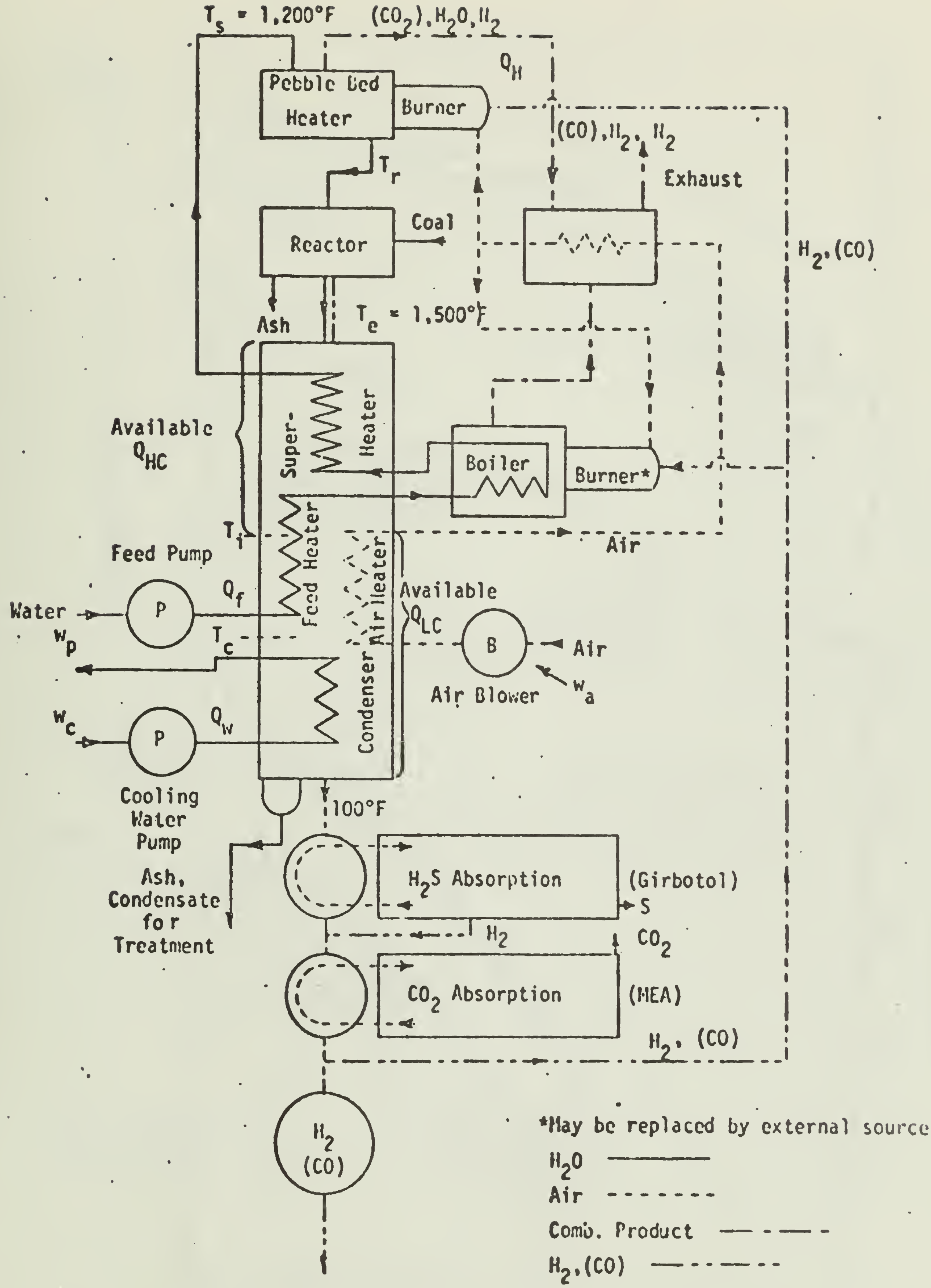


Figure 2 Basic System

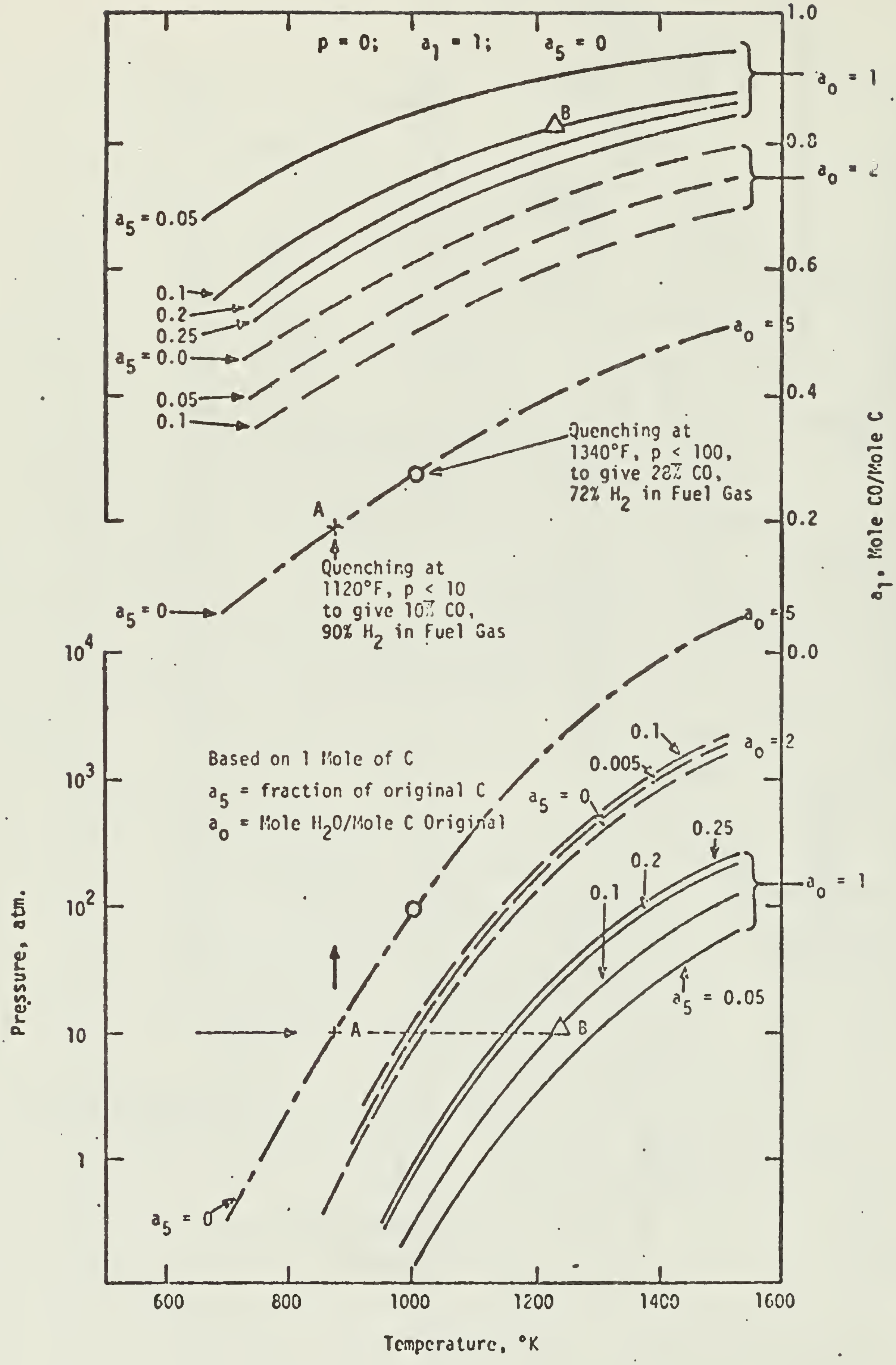


Figure 3 Equilibrium Relations of C-H_2O Reaction

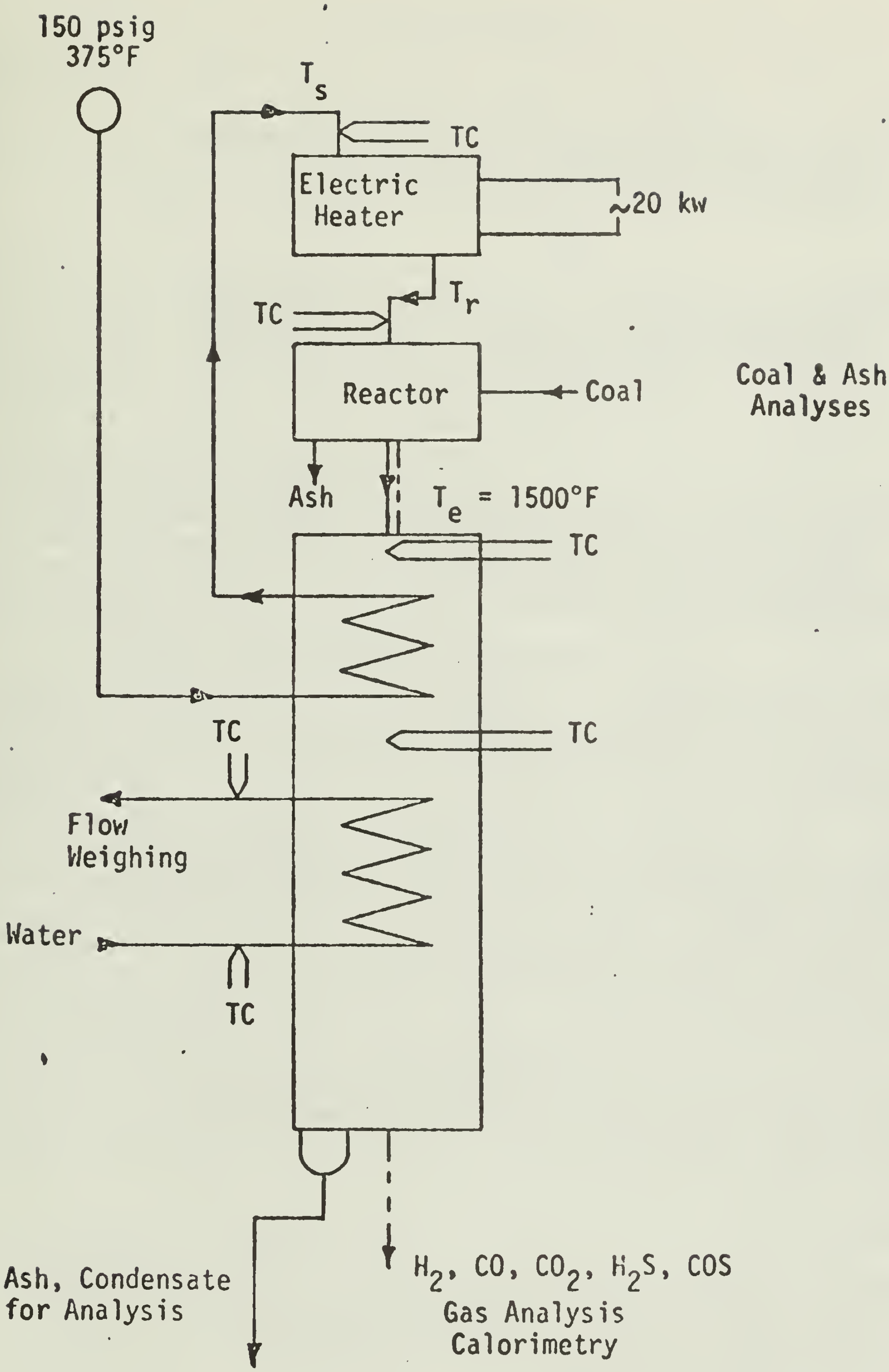


Figure 4 Phase 1 System

March 12, 1975

Additional note to OCR Proposal No. U50233GA
"A Steam Process for Coal Gasification"

by

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University of Illinois at Urbana-Champaign
Urbana, Illinois
61801

Presentation of further details on the basic knowledge and experimental facts on the steam process for coal gasification appears warranted at this time. The experimental basis of the proposed system has been presented in the following references:

1. O. Jensen, "A new electric process for the carbonization of non-coking bituminous coal," J. Inst. Fuel <u>23</u> (129), 54-5 (1950).
(Experiment at 1000°C steam, briquetted coal, produced 500 Btu/scf gas)

2. W. H. Oppelt, T. W. Kemps, C. H. Gronhovd, W. R. Kube, and R. McMurtrie, "Production of crude ammonia-synthesis gas from North Dakota lignite in an annular-retort gasifier," U.S. Bur. of Mines, Rept. Invest. 5297 (1957).
(Experiment with steam at atmospheric pressure, heated electrically produced 300 Btu/scf gas)

3. J. L. Johnson, "Kinetics of bituminous coal char gasification with gases containing steam and hydrogen," Advances in Chemistry Series, No. 131, Coal Gasification, the American Chemical Society (1974), 145-178.
(Measured reaction rate of steam and coal heated to 1900°F in a closed chamber)

4. "Electrically heated fluidized-bed reactor," Chem. Eng. News <u>42</u> (45) 68-9 (1964); also W. M. Goldberger, J. E. Hanivay, Jr., and B. G. Langston, "The electrothermal fluidized bed," Chem. Eng. Prog. <u>61</u> (2), 63-7 (1965).

Both references 1 and 2 carried out gasification of coal successfully with steam alone and at atmospheric pressure where the steam density is below 0.037 lbm/cu. ft. because of superheating by the electric energy. At 3000°F even at 10 atm. the density is about 0.07 lbm./cu. ft. Therefore even if one bases his estimation on the idea of contact density alone, the illustrated test condition is more than enough to produce the desired reaction.

It is readily shown, from correlating the data in Ref. 3 that the reaction rate constant of steam-carbon reaction is given by a kinetic frequency factor of 140 m/sec and an activation energy of 34.1 kcal/g-mole. The rate of carbon conversion in mass per unit time for given surface area and steam density is readily computed. For a surface temperature of 1540°K (2300°F) and a steam pressure of 10 atm., and a particle size of 1mm, a reaction rate of 120 kg/sec for each ton (900kg) of carbon is maintained. (1) & (3

The heat of the above reaction is supplied by the steam suspending the particles via conduction and convection maintained by a difference between the steam temperature and the carbon surface temperature, and enhanced by relative motion between the particle and the steam (see, for instance, S. L. Soo, "Fluid Dynamics of Multiphase Systems," Blaisdell, 1967, p. 22). For a relative velocity of 1.5 m/sec in the above numerical example, all the heat of reaction is supplied by the steam at a temperature of 1612°K (2440°F). Hence the reaction rate can be sustained by the heat supplied by the steam. At the lower temperatures, a lower temperature difference than in this example will be needed to supply the heat of reaction. The relative motion produced in a spouting bed or a fluidized bed is desirable for increasing the rate of heat transfer from steam. (1) & (: (4)

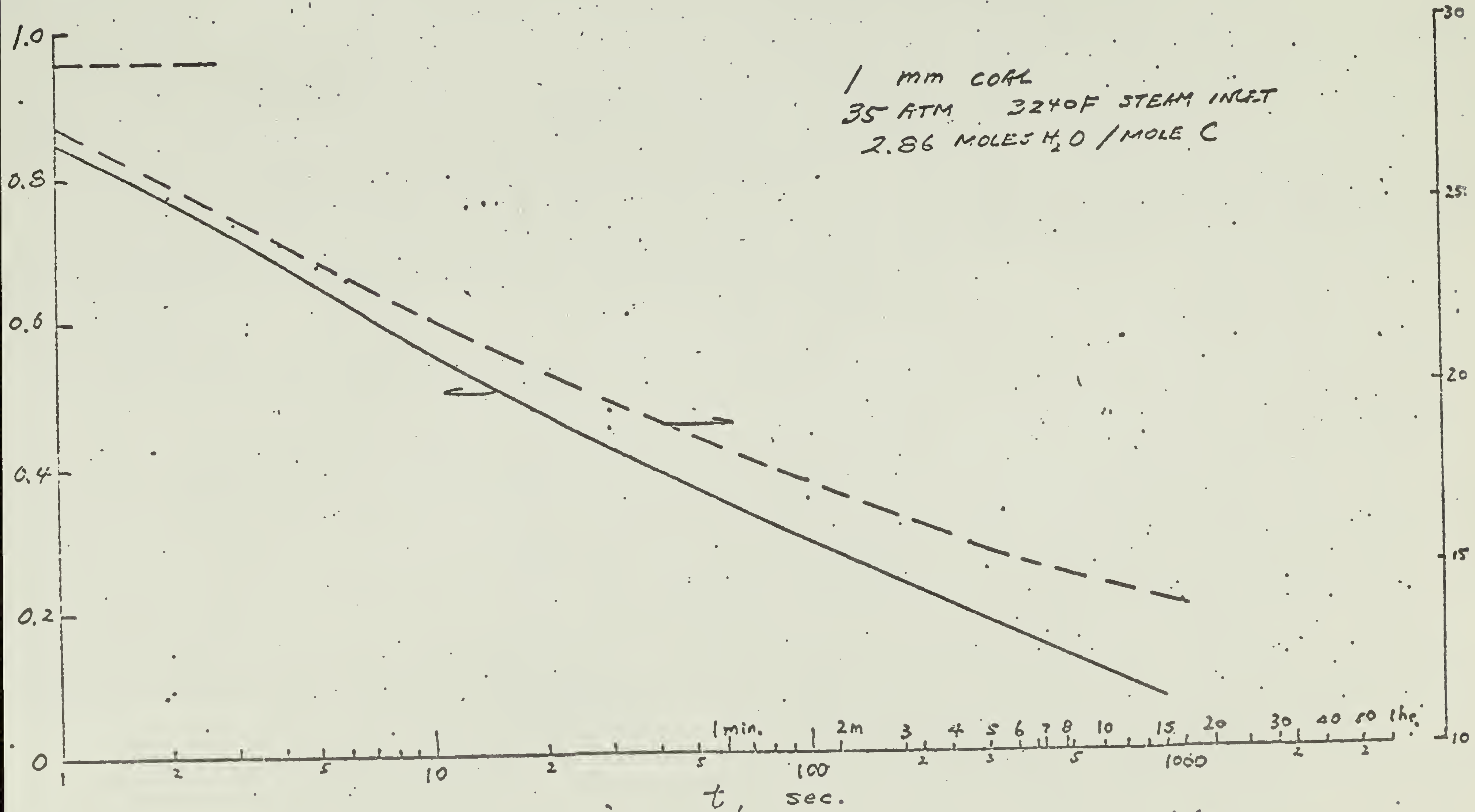
The above analysis shows that the success of gasification of coal is dependent on: particle size (or solid surface area), residence time, reaction rate which is a function of temperature, the gas phase density, the relative velocity of phases, and the concentration of the reactant. The reactor design is a result of balancing all these factors. Based on the reaction rate as determined in Ref. 3 in the above, the fraction reacted and the gas temperature vs. time is shown in Fig. A1. This means that a residence time of 20 minutes is needed for 1mm. coal at steam temperature of 3240 F at the inlet and a pressure of 35 atm., or 70 min. at 10 atm. Even the latter residence time is quite suitable for a 500 ton/day plant because that means a primary reactor of 7.5 ft. inside diameter and 80 ft. high holding 25 tons of coal. The size can be reduced if we design at 35 atm. but the balance is in the cost of machinery and related components (compressor and turbine, etc. and the the design of the pebble bed heater) vs. the size of reactor and other pressure vessels. (5)

Reference 4 shows the desirability of relative motion and that low vapor density at high temperature is not the only controlling factor. We have not yet settled on a fluidized bed or a spouting bed. The spouting bed, if properly designed, is useful because its contribution to the controlled residence time and greater relative motion than an ordinary fluidized bed. It should be complemented by a settling chamber for the fines in the coal to complete the reaction. (4)

The pebble bed heater is perhaps not as much a problem as an oxygen plant. The fail-safe feature of the proposed process is unmatched by others. (2)

The design has not been finalized with regard to using a moving pebble bed heater or several fixed pebble beds with switching. With regard to a moving pebble bed, the writer has industrial experience of design of risers in catalytic crackers where the conditions are similar to a moving pebble bed. It can be seen that because of high gas viscosity at the high operating temperature and the gas density produced by the pressurized operation will reduce attrition of the pebbles in comparison to operating a pebble bed heater at atmospheric pressure. (5) (2)

There is the disadvantage of the need for valving in using fixed pebble beds, but their construction for high temperature and pressures is well known. In the 1950's, air to produce Mach 5 in a wind tunnel was heated to above 3500°F in a magnesia pebble bed heater. The pebbles were intermittently heated by hot gas at 4500°F from an oil burner and at slightly above atmospheric pressre, and blown with air at 50 atm. or higher. The greatest advantage is that by switching among several fixed bed heaters, the heating cycle of pebbles can be carried out near atmospheric pressure, thus there is saving in the machinery for air compression. Steam pressures of 35 atm. or higher can be readily designed for with the attendant advantages even for a small plant. Coal locks will also be pressurized with steam. In this case, air compression is entirely eliminated; motor driven air blowers will be sufficient. Note that the steam pressure is achieved by pumping water, which consumes only a fraction of the energy required by gas compression. (2)



1 mm COAL
35 ATM 3240F STEAM INLET
2.86 MOLES H_2O / MOLE C
1.0
0.8
0.6
0.4
0.2
0
30
25
20
15
10
1 min.
2m
3
4
5
6
7
8
10
15
20
30
40
60 hrs.
1
2
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100
1000
t, sec.

ECONOMIC IMPACT ON THE STATE OF ILLINOIS OF THE MEDIUM BTU COAL GASIFICATION DEMONSTRATION FACILITY AT THE UNIVERSITY OF ILLINOIS AT URBANA-CHAMPAIGN

Michael Rieber
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October, 1974

ECONOMIC IMPACT ON THE STATE OF ILLINOIS
OF THE MEDIUM BTU COAL GASIFICATION
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A. Introduction

The importance of coal to the State of Illinois can be seen by comparing the value of coal production to the value of all other mineral production in the state. In 1969, coal as a percent of total value was 42.4 percent. In 1970, it was 46.6 percent.[1] Unfortunately, Illinois coal production does not match its reserve position. According to the National Petroleum Council, Illinois contains 15.2 percent of the estimated total reserves of coal in the United States. In 1971, Illinois coal production was only 10.6 percent of total U.S. coal production. Furthermore, the use of coal has been declining relatively in almost every area of fuel consumption.

Part of the problem is transportation, part of the problem is air pollution control, and part of the problem is that coal in its natural form is clearly the least flexible of all fossil fuels. Because it is solid and contains substantial amounts of waste, coal involves greater difficulty at every stage of the use process. It is more difficult to extract, transport and handle in consumption than either oil or gas. Furthermore, after combustion an ash residue remains that creates a disposal problem. As a result, coal is used in its

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[1] U.S. Bureau of Mines, Minerals Yearbook 1970, Vol. 2, Table I, p. 235.

natural form only when it is cheaper than other fuels. Moreover, the use of coal in its natural form indicates that the economies of scale in coal handling are such that only large users find that they can cheaply overcome the cost disadvantages. This fact largely explains the concentration of coal use among large consumers of fuel.

Increasingly, industrial, commercial and government establishments have restricted their use of coal. It has long been a desire of the coal industry to overcome these drawbacks by developing economically viable techniques for manufacturing synthetic oil and gas from coal. It has also been argued that the impending exhaustion of domestic conventional oil and gas supplies would make the need for such synthesis inevitable.

The coal gasification proposal is a plan to design, construct, and operate a coal gasification plant which would use high sulfur Illinois coal to supply the University of Illinois' Abbott Power Plant. This plant would use 500-600 tons of coal per day to produce a medium Btu gas. For most industrial firms and institutions, generating either electricity, heat or both, the gasification facility will constitute a demonstration plant. For large systems, such as an electric utility, it will serve as a pilot plant. Thus, the facility will serve as a demonstrator in a learning process involving the major natural resource of the State of Illinois and other major coal states. It is a long step towards satisfying three coals: first, Project Independence; second, air pollution

control regulations; and third, a revitalization of coal mining in the high sulfur bituminous coal districts, a major energy source east of the Mississippi.

B. Coal in the State of Illinois

The problem facing the State of Illinois can be seen in Table I. Here it can be seen that 1970 total production, as a percent by sulfur content, does not match the reserves of coal that exist within the state. The imbalance has been further aggravated by air pollution control regulations, which mean that for the years after 1970, coal production is weighted even more heavily toward the low sulfur end while the percentage of reserves in each sulfur category remains the same. It may be noted in passing that for the 1.5 to 1.99 sulfur content category, reserves are negligible while production is indicated at 6.3 percent. This apparent discrepancy occurs because washing of coal, as part of the production process, lowers the sulfur content of the coal somewhat. The table indicates that it is clearly within the interest of the state to do everything possible to enable production of its high sulfur coal reserves.

Table II indicates the level of sulfur content for coal shipped to major users. It must be pointed out again that the data are for 1970. As air pollution control regulations tightened, the state is less able to consume 3.5 percent sulfur coal in its electric utilities or 2.8 percent sulfur coal in other sectors. This will cause a drain on what little low sulfur coal exists within the state and will lose markets for Illinois coal.

TABLE I

Distribution of Illinois Coal Production and Reserves by Sulfur Content

Sulfur Content (Percent, Weight)	1970 Total Production[1] (Percent)	Reserves[2] (Percent)
0.0 -- 1.49	13.8	1.29
1.5 -- 1.99	6.3	--
2.0 -- 2.49	6.5	.82
2.5 -- 2.99	22.8	12.79
3.0 -- 3.49	27.6	25.95
3.5 -- 3.99	13.7	44.46
over 4.0	9.3	14.70
TOTAL	100.00	100.01

(1) Compiled by Illinois State Geological Survey.

(2) Department of Health, Education and Welfare, Control Techniques for Sulfur Oxide Air Pollutants. January 1969, Table 4.2, p. 4.11.

TABLE II

Illinois: Average Sulfur Content of

Coal Shipped, 1970

Electric Utilities	3.5 Percent
Coke and Gas Plants	0.8 Percent
Other Industrial and Retail	2.8 Percent
All Other	2.8 Percent
Exports	--

Source: U.S. Bureau of Mines, Minerals Yearbook, 1970, Vol. I, Table 41, p. 384.

C. The Medium Btu Coal Gasification Plant

The proposed coal gasification plant, in addition to supplying heat and power for the University, has a number of specific uses. First, it will demonstrate the use of Illinois high sulfur coal in a manner that is well within air pollution control regulations. Additionally, it may be noted that the coal supplied to the gasifier need not have much prior preparation. Second, the plant will demonstrate to industry, large commercial and government complexes, and small utilities, a method of using coal to generate process heat and steam, electric power and, if the coal gasifier is close to the establishment, the gas can be used for air conditioning purposes. Third, for larger utilities, the plant will serve as a pilot plant for medium Btu gasification. Fourth, the gasification plant can serve as a training site for Illinois' personnel (Environmental Protection Agency and Illinois Commerce Commission) who will be responsible for future hearings relating to the certification of coal gasification plant. Fifth, the plant will serve as a test base for future experimentation.

Because the plant produces a medium Btu gas, a number of special features arise. First, the gas can be piped about 25 miles. This demonstrates siting flexibility to future users. Second, it need not use pure oxygen in the gasification process. Therefore, construction costs and operating costs are lower. Third, the use of much auxiliary equipment is eliminated. And

fourth, the water use is low. Again this means that siting can be accomplished almost anywhere within the State of Illinois.

Three other advantages accrue to this plant. First, it is clean. The hydrogen sulfide is turned into sulfur, and therefore, the disposal problem is small. Because of the indirect heating, there are clean stacks and no air pollution problems. Second, the plant is designed to accomodate varying qualities in the coal supply. And third, with add-ons, the plant can be made to utilize solid waste, thereby lessening disposal problems for some cities and towns.

D. Coal vs. Fuel Oil: Prices

Tables III and IV show the reason why the University, and others, are anxious to move away from the consumption of No. 2 distillate fuel oil. The rapid increase in distillate oil prices is readily apparent. It is also apparent that there have been large increases in the prices of coal. However, not of the same order of magnitude. Furthermore, and for our purposes much more interesting, is the fact that for any given time period, the price of high sulfur coal is from 50 percent to 66 percent of the price of low sulfur coal. A shift then in terms of the ability to burn or utilize high sulfur coal involves a great saving to any establishment.

Table V is an indication of the behavior of delivered coal prices to electric power generating utilities in a recent time period. The note at the bottom of the table is a clear indication of the advantages, in terms of price, of the ability

TABLE III

Distillate No. 2 Oil

Spot Prices

	Chicago		Mid-Continent (Group 3)	
	¢/gal.	$/MBtu	¢/gal.	$/MBtu
9/30/74	26.50-33.00	1.91-2.38	23.00-27.50	1.66-1.98
1/7/74	17.00-21.00	1.22-1.51	17.25	1.24
1/1/73	11.00	.78	10.00	.72
1/3/72	11.00	.78	9.25	.67
1/4/71	11.50-11.75	.83- .85	10.25-10.50	.74- .76

Source: <u>Oil and Gas Journal</u>. No. 2 oil at 5,825,000 Btu/BBL.

TABLE IV

Average Price of Coal Received by

Illinois Utilities -- by Sulfur Content (percent)

(¢/MBtu)

	>3.1	2.01-3.0	1.51-2.00	1.01-1.50	0.51-1.0	<0.5
5/74	45.6	50.2	58.3	57.0	108.3[1]	71.1
1/74	38.4	46.4	46.1	55.4	65.4	71.3

	>3.0	1.01-3.0	<1.0
1/73	32.07	37.11	65.34
7/72[2]	31.50	33.74	61.05

Source: Compiled by the Illinois State Geological Survey.

(1) None received in Illinois, quote is for Indiana.

(2) The data are not available by state and sulfur levels prior to July 1972.

TABLE V

Behavior of Delivered Coal Prices, 1969-1972

Selected Company Reports

(Cents/MBtu)

	1969	1972	Change
Commonwealth Edison	28.2	43.2	15.0
Illinois Power Company	23.2	28.1	4.9
Central Illinois Public Service Company	23.8	36.5	12.7
Central Illinois Light Company	25.5	33.9	8.4

Source: R. Gordon, The Competitive Setting of the U.S. Coal Industry, 1946-1990, (mimeo), Table 2.11, p. 2-38.

Note: Delivered coal prices during the second half of 1972 in Illinois were:

Percent Sulfur	July (Cents/MBtu)	December (Cents/MBtu)	Change (Percent)
≤ 1	61.05	62.76	2.8
1.01-3.0	33.74	36.33	7.7
≥ 3.0	31.50	31.57	0.2

Source: Op Cit., Table 2.12, p. 2-40.

to utilize a high sulfur coal rather than a low sulfur coal. Characteristically, while the prices were rising in 1972, the price increase for the high sulfur coal was almost negligible. This is due to the fact that the market for high sulfur coal, given air pollution control standards, is very small. Perhaps most important is the increasingly fine detail, in terms of sulfur content, with which coal prices are reported. This is a reflection of the recent division of the coal market in terms of demand. Prior to 1972, it was not considered generally useful to divide coal data by sulfur content. The figures in the footnote to Table V may be compared with the data for greater than 3.1 percent sulfur coal in Table IV. In both of these tables, it must be realized that the prices are relevant primarily to coals in the 3.1 to 3.5 percent sulfur category. As a matter of fact, virtually no coal can be sold with a sulfur content higher than 4.0 percent. Consequently, such coals, of which there is a great amount in the State of Illinois, are presently valueless.

Table VI is an indication of coal prices to industrial consumers in Illinois in 1967, prior to the establishment of air pollution control standards. It may be noted that at that time the price differential between high and low sulfur coal was less than it is today. Additionally, comparing Table VI with Table IV shows that the price increase for high sulfur coal was less than the increase for low sulfur coal. Given air pollution control standards, this is to be expected. Tables VII and VIII

TABLE VI

Industrial Consumer Prices of Coal 1967

(Cents/MBtu)

Destination	Sulfur Ranges, Weight Percent			
	0.7	0.8-0.9	1.8-2.0[1]	2.9-3.7
Chicago, Illinois	40-43	34-41	--	27-34
Davenport-Rock Island-Moline, Iowa-Illinois	42-68	37-45	--	32-37
St. Louis, Missouri-Illinois	40-43	34-41	--	25-30

Source: U.S. Department of Health, Education and Welfare, <u>Control Techniques for Sulfur Oxide Air Pollutants</u>, January 1969, Table 4-13, pp. 4-46,47.

[1] No data on coal prices available.

give the price history of coal and No. 2 fuel oil in the State of Illinois for the years 1951 to 1969 and 1971. It should be noted that between 1951 and 1970, coal prices increased slightly more than 15 percent. Between 1970 and 1971, they increased slightly more than 15 percent in the single year. However, this increase was due as much to a change in the sulfur content of the coal, and a change in coal value due to the sulfur content, as it was to all other market factors combined.

Table VIII indicates the constancy of No. 2 fuel oil prices in the period 1951 through 1969. The rapidity of the recent price increases in No. 2 fuel oil can be seen by comparing Table VIII with either the first or the third column of Table III. In combination, the set of price tables indicates that relative to No. 2 fuel oil, coal is a good buy. It is especially a good buy if high sulfur coal can be used. As indicated in the start of this paper, coal gasification is a prime means by which high sulfur coal can be utilized.

E. The Market for Medium Btu Gasified Coal

Successful demonstration of a coal gasification plant implies that others will follow its use. This would also imply greater use of coal, particularly high sulfur coal from the State of Illinois. It has been noted above that among the major potential users of the gasification plant are industrial, commercial, and government complexes. Table IX indicates the use of coal by manufacturing industries. While the table refers to the entire United States, it is certainly indicative of industrial states such as the State of Illinois.

TABLE VII

Cost of Coal in Electric

Power Generation, Illinois,

1951 - 1971

(Cents/MBtu)

Year	Cost
1951	25.6
1952	25.5
1953	25.6
1954	24.7
1955	23.8
1956	24.1
1957	25.0
1958	24.9
1959	25.0
1960	24.9
1961	24.8
1962	24.8
1963	24.7
1964	24.4
1965	23.9
1966	23.6
1967	23.7
1968	24.5
1969	26.0
1970	29.5
1971	34.0

Source: R. Gordon, The Competitive Setting of the U.S. Coal Industry, 1946-1990, Table 2.15, p. 2-43.

Note: Between 1951 and 1970 prices increased 15.6 percent. Between 1970 and 1971 prices increased 15.2 percent.

TABLE VIII

Average Refinery Prices of No. 2 Fuel Oil

1951 - 1969

(Cents/Gal.)

Year	Chicago District	Oklahoma Group 3
1951	10.76	8.46
1952	10.21	8.10
1953	10.01	7.91
1954	10.07	8.38
1955	10.05	8.63
1956	10.63	9.23
1957	10.48	9.67
1958	10.12	8.89
1959	10.51	9.12
1960	10.01	8.78
1961	10.20	8.92
1962	10.71	9.15
1963	10.62	9.24
1964	9.11	8.05
1965	9.25	8.56
1966	9.39	8.84
1967	9.54	9.23
1968	9.86	9.39
1969	10.12	9.63

Source: American Petroleum Institute, Petroleum Facts and Figures, 1971 Edition, p. 451.

Note: Between 1951 and 1969 Chicago prices fell six percent, Oklahoma-Group 3 prices (for northern shipment) rose 13.8 percent.

TABLE IX

Reported Coal Consumption and

Net Electric Power Production

by Manufacturing Industries, 1967

	Thousands of Tons of coal a/	Million Kilowatt Hours Generated b/
Food and Kindred Products	5,889.2	2,191.1
Tobacco	348.6	112.9
Textile Mill Products	1,810.7	498.8
Lumber and Wood	253.8	621.7
Furniture and Fixtures	198.1	46.4
Paper and Allied Products	12,839.7	22,987.1
Printing and Publishing	32.6	6.9
Chemicals and Allied Products	19,652.8	21,372.7
Petroleum and Coal Products	865.6	4,088.7
Rubber and Plastic Products	1,882.6	582.3
Stone, Clay and Glass	11,211.2	1,193.1
Primary Metal Industries	7,700.5	22,526.7
Fabricated Metal Products	1,036.4	43.5
Machinery, Except Electrical	1,323.0	495.4
Electrical Equipment and Supplies	806.8	187.6
Transporation Equipment	3,194.5	2.0
Instruments and Related Products		576.0
Miscellaneous		1.5
TOTAL	69,045.8	77,534.4

Source: U.S. Census.
a/ The data here are compiled from surveys of users and are incomplete because the Census by law cannot release data that provides information about individual firms.
b/ From all sources.

The data in Table IX suggests that many industrial coal users employ coal to generate electricity. This may be indirectly inferred from the association between high levels of coal use and substantial electric power output. This electricity is probably jointly produced with process steam. Where both process steam and electricity are needed, it is often most efficient to generate steam in modern boilers at higher temperatures and pressures than are desired for process use and to pass the steam through a turbine producing both electricity and steam of the necessary characteristics. Presumably these uses are subject to the same air pollution challenges as those facing electric utilities. It is, however, these industries which are prime candidates for the demonstration effect of the coal gasification plant.

Table X is an indication of United States consumption of bituminous coal starting post-World War II. Of particular relevance to the coal gasification plant, proposed here, is the decline in coal consumption by other manufacturing and mining industries and retail deliveries to other consumers. An indication of the size of this potential market can be found by taking the difference between the 1971 consumption levels for those two categories and relating them to any earlier period prior to air pollution control or, even earlier, prior to the low oil prices of the 1960's. It is this market which may be recovered for coal by the medium Btu gasification project. Of this increase in output, Illinois would have a major share.

TABLE X

United States Consumption and Exports of Bituminous Coal, 1946-1971

(Thousands of Net Tons Consumed in the United States)

Year	Electric Power Utilities	Railroads (Class I)	Coking Coal	Steel & Rolling Mills	Cement Mills	Other Manufacturing & Mining Industries a/	Retail Deliveries to Other Consumers	Total U.S. Consumption	Exports
1946	68,743	110,166	83,288	12,151	6,990	120,364	98,684	500,386	41,197
1947	86,009	109,296	104,800	14,195	7,919	127,015	96,657	545,891	68,667
1948	95,620	94,838	107,306	14,193	8,546	112,612	86,794	519,909	45,930
1949	80,610	68,123	91,236	10,529	7,966	98,685	88,389	445,538	27,842
1950	88,262	60,969	103,845	10,877	7,923	97,904	84,422	454,202	25,468
1951	101,898	54,005	113,448	11,260	8,507	105,408	74,378	468,904	56,722
1952	103,309	37,962	97,614	9,632	7,903	95,476	66,861	418,757	47,643
1953	112,283	27,735	112,874	8,764	8,167	96,999	59,976	426,798	33,760
1954	115,235	17,370	85,391	6,983	7,924	78,359	51,798	363,060	31,041
1955	140,550	15,473	107,377	7,353	8,529	91,110	53,020	423,412	51,277
1956	154,983	12,308	105,913	7,189	9,026	94,772	48,667	432,858	68,553
1957	157,398	8,401	108,020	6,938	8,633	88,566	35,712	413,668	76,446
1958	152,928	3,725	76,580	7,268	8,256	82,327	35,619	366,703	50,291
1959	165,788	2,600	79,181	6,674	8,510	74,365	29,138	366,256	37,253
1960	173,882	2,101	81,015	7,378	8,216	77,432	30,405	380,429	36,541
1961	179,629	b/	73,881	7,495	7,615	78,050	27,735	374,405	34,970
1962	190,833	b/	74,262	7,319	7,719	79,453	28,188	387,774	38,413
1963	209,038	b/	77,633	7,401	8,138	83,467	23,548	409,225	47,078
1964	223,032	b/	88,757	7,394	8,679	83,639	19,615	431,116	47,969
1965	242,729	b/	94,779	7,466	8,873	86,269	19,048	459,164	50,181
1966	264,202	b/	95,892	7,117	9,149	89,941	19,965	486,266	49,302
1967	271,784	b/	92,272	6,330	8,922	84,009	17,099	480,416	49,528
1968	294,739	b/	90,765	5,657	9,391	83,054	15,224	498,830	50,637
1969	308,462	b/	92,901	5,560	9,131	78,557	14,666	507,275	56,234
1970	318,921	b/	96,009	5,410		83,207	12,072	515,619	70,944
1971	326,280	b/	82,809	5,560		68,862	11,351	494,862	56,633

Source: U.S. Bureau of Mines data.

a/ Includes bunker fuel.

b/ Data included in other manufacturing and mining industries.

Again because of the characteristics of the gasification plant, there would be no reason not to use high sulfur run-of-the-mine Illinois coal. Table XI shows much of the same material found in Table X in a slightly different form. With respect to household and commercial, as well as industrial sales and consumption of coal, the loss of coal in terms of share of the market in each case is made perfectly apparent by moving from the 38.17 percent for household and commercial consumption in 1947 to the 4.61 percent in 1966. Similarly for industrial use, coal as a percent of all fuels used in this category was 55.39 percent in 1947 but was only 31.67 percent of all fuels consumed by the industrial group in 1966.

Table XII supplies some data which shows the kind of market that may be available to Illinois coal assuming gasification at a medium Btu level. If one assumes that the entire burden of additional consumption of Illinois high sulfur coal falls only on the State of Illinois, one may compare, for example, the consumption of coal by retail dealers and all others in 1957 with their consumption in either 1970 or 1973. Assuming further that there are no additional industrial or commercial establishments in the state in the years after 1973, a comparison between 1957 and 1970 indicates that 11 million tons of coal per year could be purchased if coal purchases were at 1957 levels. This represents an increase of 26 percent over 1970 Illinois sales to consumers.

TABLE XI

U.S. Consumption of Coal: Household-
Commercial and Industrial Consumers
1947 - 1966

	Household & Commercial		Industrial	
Year	10^{12} Btu	Percent of all Fuels	10^{12} Btu	Percent of all Fuels
1966	573	4.61	5806	31.67
1965	546	4.60	5640	32.14
1964	560	5.02	5362	31.56
1963	671	6.07	5014.6	31.66
1962	798.6	7.26	4761.6	31.78
1961	782.9	7.52	4693.7	41.00
1959	814.9	8.36	4691.8	33.77
1957	981.3	11.26	5792.4	40.07
1955	1443.7	16.74	5976.1	43.14
1953	1614.8	20.82	6056.9	44.86
1950	2252.5	29.67	5830.4	48.01
1947	2585.5	38.17	7013.6	55.39

Source: Department of Health, Education and Welfare, Control Techniques for Sulfur Oxide Air Pollutants, January 1969, Table 4-1. p. 4-3.

TABLE XII

Illinois: Physical Volumes of Coal Shipped to Market

Market	1957 (000 Tons)	1966 (- - - - - Index 1957 = 100	1967	1968	1969	1970 - - - - -)	1970[1] (000 Tons)	1973[2] (000 Tons)
Electric Utilities	18,584	149.6	158.7	151.9	163.5	158.5	29,460	32,465
Coke and Gas Plants	3,925	92.4	87.9	78.2	94.6	94.0	3,690	2,968
Retail Dealers	8,623	49.4	47.2	38.4	35.7	30.0	2,587	934
All Others	11,586	92.2	83.6	76.5	69.6	56.8	6,581	4,261
TOTALS	42,718	108.6	109.3	101.7	105.9	99.0	42,291	40,628

Source: U.S. Bureau of Mines, Minerals Yearbook, 1970, Vol. I, Table 40, p. 381.

[1] Derived from index.

[2] Compiled by Illinois State Geological Survey.

Table XIII shows the loss of sales to these consumers. Column one shows total shipments of coal to District 10 from all districts in the United States. Column two shows the percent of sales in District 10 (Illinois) originating in the State of Illinois. It may be noted that as early as 1969 there was some tendency for such sales to decline, as a percentage. Clearly, as low sulfur requirements come more to the fore, even greater declines may be expected. Column three shows the decline in the importance of coal shipments to retail dealers and all others as a percentage of total shipments in the State of Illinois. Column four shows that shipments of coal to retail dealers and all others in the State of Illinois from outside the state also declined. However, as may be seen in the note at the bottom of the table, as a percentage of the sales to retail dealers and all others, between 1966 and 1970, shipments from out of state gained in relative importance to shipments originating within the state. Within this category of retail dealers and all others, which is the primary market for coal gasification plants, Illinois is losing ground to other states within its own state.

An alternative to coal gasification is the use of high sulfur coal accompanied by stack gas desulfurization or scrubbing. Table XIV gives some estimates of stack gas scrubbing costs. These are by now slightly out of date because the capital costs have risen considerably. Nevertheless, it can be seen that the order of magnitude of the costs in 1972-1973, is roughly the same, at least for the high, as the cost of coal itself.

TABLE XIII

Illinois Coal (District 10)

Year	(1) Total Shipments to District 10 (000 Tons)	(2) District 10 origin (% of Col. 1)	(3) Shipments to Retail Dealers and All Others from District 10 (% of Col. 1)	(4) Shipments to Retail Dealers and All Others from Other districts* (% of Col. 1)
1966	46,382	81	29.3	8.5
1967	46,710	82	26.5	7.5
1968	43,465	82	25.1	7.4
1969	45,244	80	22.6	6.4
1970	42,311	80	19.6	5.9

Source: U.S. Bureau of Mines, Minerals Yearbook, 1970, Vol. II, Table 6, p. 240.

*Shipments to retail dealers and all others from out of state amounted to the following percentages of the state consumption in these classes.

1966 - 35.9
1967 - 34.7
1968 - 35.6
1969 - 35.1
1970 - 37.4

TABLE XIV

Estimates of Stack Gas Scrubbing Costs

	High	Low
SOCTAP Report (1973)		
Total Costs	(Cents/MBtu)	
50 percent utilization	44.5	12.5
64 percent utilization	38.0	10.3
75 percent utilization	34.6	9.3
80 percent utilization	33.3	8.9
	(mills/KWhe)	
80 percent utilization	3.0	0.8
Federal Power Commission		
Total Costs	(Cents/MBtu)	
64 percent utilization	48.0	35.6
75 percent utilization	44.0	32.6
80 percent utilization	42.6	31.5
Commonwealth Edison		
Total Costs	(Cents/MBtu)	
New Plant		
64 percent utilization	62.5	50.5
75 percent utilization	58.1	45.0
80 percent utilization	55.5	42.9
Older Plant		
64 percent utilization	90.5	70.0

Source: R. Gordon, The Competitive Setting of the U.S. Coal Industry, 1946-1990, mimeo, Tables 7.9-11, pp. 7.65-68.

F. The Pay-out Period: Return on the State Investment in the Coal Gasification Facility

The State of Illinois is entitled to a return on its investment in a coal gasification facility. One dimension of this return may be seen by examining the tax system. According to the Department of Revenue, a retailers' occupation tax, on the value of the coal, accrues to sales to customers within the state, unless specifically exempt. The state rate is four percent. Additionally, the counties or municipalities can charge up to one percent. Some counties and municipalities do not collect the tax, but none of these are important coal producers. An example may indicate the pay-out period over which the state investment can be recovered.

As seen in Table IV, the price of high sulfur coal (used in the gasification plant) was 45.6 cents/MBtu in May, 1974. This is equivalent to $10.94 per ton. At a five percent tax rate, state and local governments receive 54.7 cents per ton for high sulfur coal. Therefore, it would take sales of 18,281,535.6 tons to return the $10 million, assuming that all sales were to taxable recipients. As this is clearly not true, let us double the amount to introduce a conservative bias (i.e., 36,563,071.2 tons). It has been pointed out before that expected users fall into the class of industrial and commercial markets. This is approximated by distributional sales to the classes; retail dealers and all others. In 1973, sales in District 10 (Illinois) to these two classes equalled 5,195,000 tons. In 1966, prior to air pollution control regulations but after

the inroads of oil and natural gas, these sales amounted to 11,002,000 tons. The difference is 5,807,000 tons. Assuming that the demonstration is a success, and that as little as one-half of the 5.8 million tons can be recaptured for coal via gasification, recovery of the state's investment can be made in about 12.5 years after the demonstration goes into effect (36.56 million tons divided by 2.9 million tons).

It should be noted that as the price of coal rises, the recovery period shortens. Furthermore, recovery via personal income taxes on new miners and business taxes on new mines and equipment are explicitly omitted.

Recovery of the state's $10 million investment can also be accomplished via fuel cost differentials after the gasification plant is built. If the plant takes six years to go into operation and the relative prices of No. 2 heating oil and high sulfur coal remain the same (absolute prices will change) then, in addition to the investment, the state will be paying $30,525,000 for fuel oil over the time period involved in construction (18,500,000 gallons X 6 years X 27.50 cents/gallon). The total, then, of $40,525,000 must be recovered in the fuel price differential.

To be conservative, assume the price of high sulfur coal is 45.6 cents/MBtu. This is too high but, as there is currently no market for very high sulfur coal, its price must be considered zero while its costs are those of extraction without profit. Assume the price of No. 2 oil is 166 cents/MBtu.

This is the lowest of the tabled figures for No. 2 oil in September 1974 (Table III). Note that in calculating the value to be recovered, a price of 198 cents/MBtu was used (27.50 cents). The price differential is 120.4 cents/MBtu. Dividing this into the money to be recovered and dividing again by the heat value of No. 2 oil, yields 5,778,307 barrels of No. 2 oil. The Abbott plant uses 440,476 barrels annually. Therefore, the value of the state's investment plus the cost of No. 2 oil consumed during construction would be recovered 13 years after completion of the gasification plant. Recovery of the $10 million investment alone would take 3.2 years.

It must be noted that the recovery of the state's investment in the coal gasification plant has been assumed by two entirely separate methods. Clearly these are co-joined and one may take an average of the two yielding approximately six years at the maximum. It must also be noted that in the calculations no credit is taken for sales of sulfur or, possibly, sulfuric acid. With respect to the gasification unit, this is in line with making conservative estimates. It must be pointed out, however, that in addition to sulfur or sulfuric acid, the output of such plants normally considered as waste can go into industrial chemicals or fertilizer.

Finally, from the data found in Tables XV and XVI, it is possible to make the following observation: If one assumes that the productivity per man per year in underground and strip mines is at the level that can be found for the year 1973, and if one compares the amount of coal shipped to retail

TABLE XV

Coal Mines and Mining Employees in

Illinois by Type of Mine, 1963-1972

Year	Number of Mines			Number of Employees		
	All Mines	Strip	Under-ground	All Mines	Strip	Under-ground
1973	56	32	24	11,350	3,615	7,794
1972	59	33	26	11,237	3,367	7,870
1971	63	36	27	10,571	3,483	7,088
1970	64	35	29	10,214	3,429	6,785
1969	62	34	28	9,591	3,647	5,944
1968	69	33	36	9,538	3,510	6,028
1967	77	44	33	8,805	3,413	5,392
1966	84	48	36	8,994	3,428	5,566
1965	97	54	43	8,790	3,320	5,470
1964	108	62	46	9,079	3,376	5,703
1963	116	71	45	8,891	3,394	5,497

Source: Illinois State Department of Mines and Minerals, Annual Coal, Oil and Gas Report, 1972.

TABLE XVI

Average Production and Average
Number of Employees per Year
per Mine in Illinois, 1963-1972

	Underground Mines		Strip Mines	
Year	Average Output per Strip Mine (tons)	Average Number of Employees per Mine	Average Output per Strip Mine (tons)	Average Number of Employees per Mine
1973	1,357,389	324	905,353	113
1972	1,219,838	303	1,024,412	102
1971	1,090,886	262	804,480	97
1970	1,090,192	233	950,530	98
1969	1,077,237	212	1,019,411	107
1968	724,568	167	1,092,535	106
1967	837,879	163	844,654	78
1966	753,671	155	751,678	71
1965	594,685	127	604,834	61
1964	540,834	124	483,164	54
1963	542,800	122	383,330	48

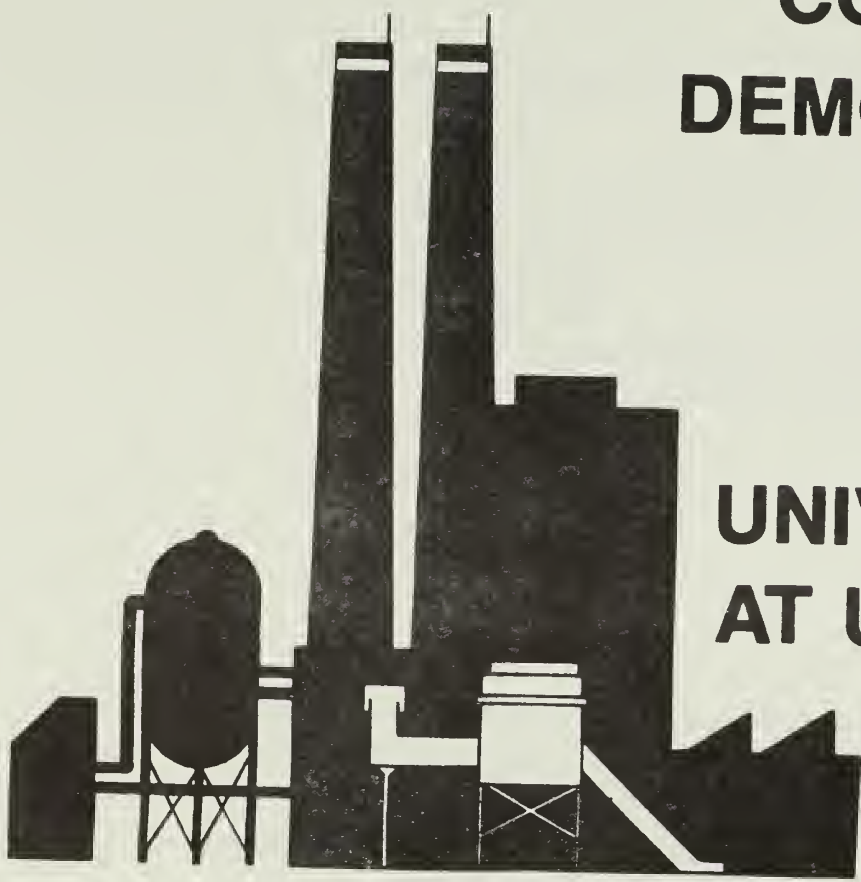
Source: Illinois State Department of Mines and Minerals, Annual Coal, Oil and Gas Report, 1972.

dealers and all others in 1973 with those amounts in 1966, and, finally, assuming conservatively that only half of the difference will be picked up by coal gasification; then one may estimate that if the number of strip and underground mines remain in the same proportion, that the number of underground mine employees will increase by 582 while the number of strip mine employees will increase by 304. If the entire increase goes to strip mines, the total additional number of mine workers will be 608 in the State of Illinois. One may also estimate that the additional coal mined will require the opening of six to seven new mines.

A PROPOSED MEDIUM-BTU COAL GASIFICATION DEMONSTRATION PLANT

FOR THE

UNIVERSITY OF ILLINOIS AT URBANA-CHAMPAIGN



PRESENTLY KNOWN OIL RESERVES OF THE WORLD*

Middle East	53%
Africa	16%
Russia & other communist countries	15%
U.S. (including Alaska)	5%
Indonesia	2%
Venezuela	2%
Mexico, Caribbean, & other South American countries	3%
Europe	2%
Canada	2%

* If the price of crude oil continues to increase, more exploration will be done and new sources will undoubtedly be discovered; but they will probably not make significant changes in the distribution during the next decade.

ENERGY CONSUMPTION* IN THE U.S. (1970-1985)

YEAR / SOURCE	1970		1975		1985[1]		1985[2]	
Coal	.44	16%	.49	13%	.53	9%	.96	20%
Oil and Gas	2.25	80	2.96	80	4.51	81	3.14	66
Nuclear	.01	0.4	.11	3	.40	7	.50	11
Hydro	.12	4	.13	4	.14	3	.14	3
TOTAL	2.82	100	3.69	100	5.58	100	4.74	100

* Energy is given in equivalent billions of tons of coal calculated at 22.6×10^6 BTU/ton.

1. Projections made by Michael Rieber and Ronald Halcrow, Center for Advanced Computation, "U.S. Energy and Fuel Demand to 1985: A Composite Projection by Users within PAD Districts."

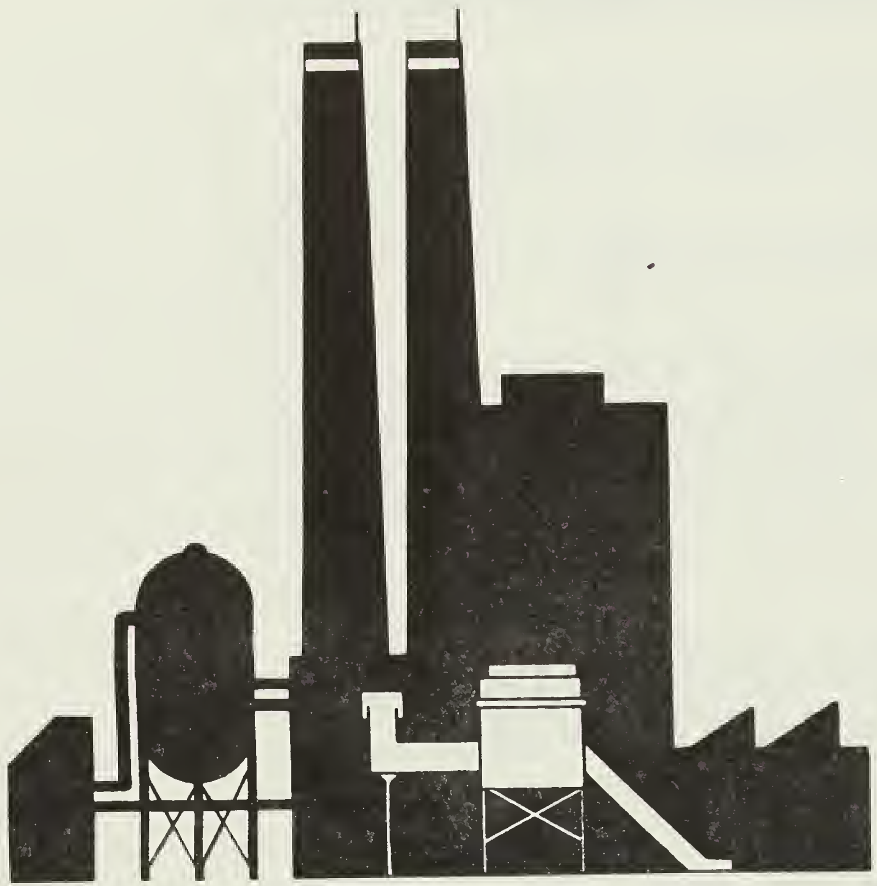
2. Projections based on series of studies of alternate solutions to the energy problem. The projections assume, (1) that we can achieve a 10 to 15 per cent reduction in per capita consumption by conservation measures, and, (2) geothermal sources, solar sources, and other sources will not contribute significantly to consumption during the next decade.

REQUIREMENTS FOR ACHIEVING SOME INDEPENDENCE BY 1985

- Double the present production of coal.
  This will require the equivalent of opening one new deep mine and one new surface mine each month for the next ten years. The resultant coal market by 1985 will be 50 billion dollars per year.

- An increase in uranium production from 14,000 tons to 70,000 tons per year.
  This represents an increase to five times our present production plus nuclear power plant construction to make use of the uranium produced.

- A continued growth in domestic oil and gas use.



ABBOTT POWER PLANT

- Built in 1940, three coal-fired boilers.
- Expanded to seven boilers by 1962.
- Converted to six oil-fired boilers after 1968 consultant's study; only three boilers can be reconverted to coal firing.
- Uses 18,500,000 gallons of No. 2 fuel oil annually.
- Produces 2.1 billion pounds of steam annually.
- Can burn either high- or medium-Btu gas when available.

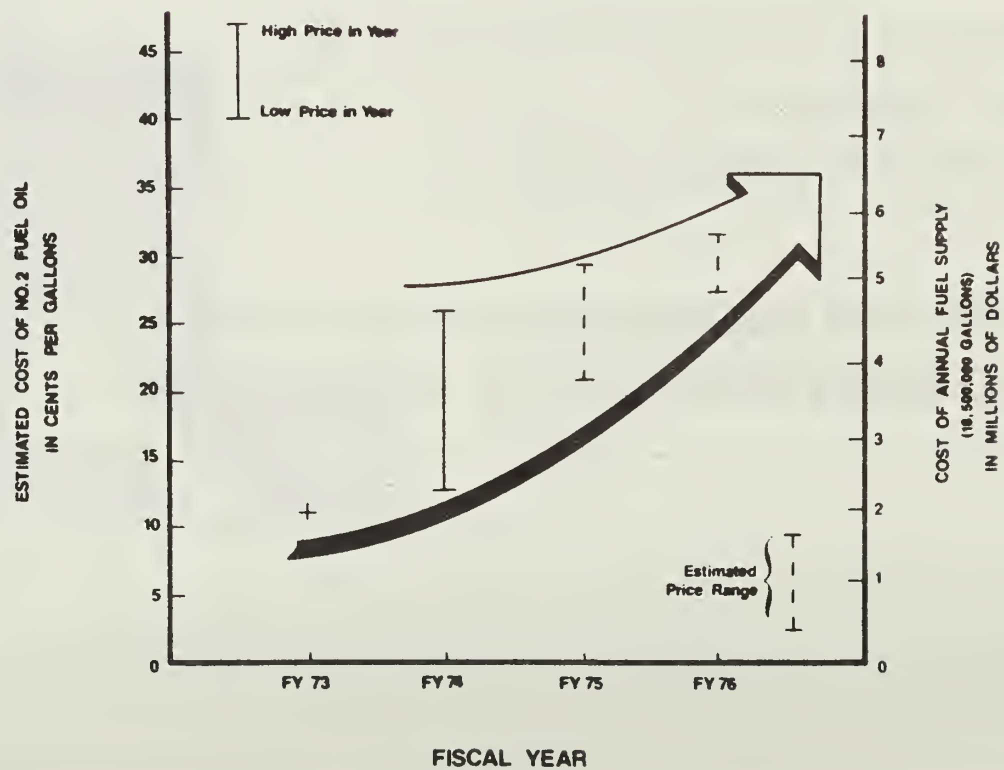
The initial phase of the Abbott Power Plant was completed in 1940 and contained three coal-fired boilers. Additions were constructed in 1948, 1956, 1961, and 1962. In the late 1960's, an indepth study was made which took into consideration the existing load requirements, the projected load requirements based upon the building program, the age of the existing equipment, and rules and regulations governing the control of air pollution. Dust emission tests conducted in 1968 had confirmed that the Abbott Power Plant was in violation of the then current Air Pollution Rules and Regulations.

The final report of this study recommended converting the three newest boilers to gas and oil firing, removing the four oldest boilers and installing three new gas- and oil-fired boilers with capacity to replace the demolished boilers and provide for future load growth. An operation utilizing No. 2 fuel oil was recommended. No. 2 fuel oil was readily available through pipeline transportation within five miles of Champaign; it eliminated environmental problems concerning particulate and future sulfur dioxide removal; it extended the time before a new chimney would be an absolute necessity; and, at that time it had a price structure that was within the guidelines of the study. In 1972, this major conversion program was completed.

For FY-74, Abbott Power Plant produced 2.1 billion pounds of steam with its six oil-fired boilers. This consumed nearly 20.5 million gallons of No. 2 fuel oil. The demand for steam during FY-75 is expected to remain constant at about 2 billion pounds equivalent to 18.5 million gallons of fuel due to a number of energy conservation measures recently instituted.

THE EFFECTS OF FUEL COST ON ABBOTT POWER PLANT

- The contract ending in June 1974 was for $.12 per gallon.
- The July 1974 dock price was $.22 per gallon. This price increase represents an additional $1,850,000 per year.
- Prices are expected to continue increasing through 1976.

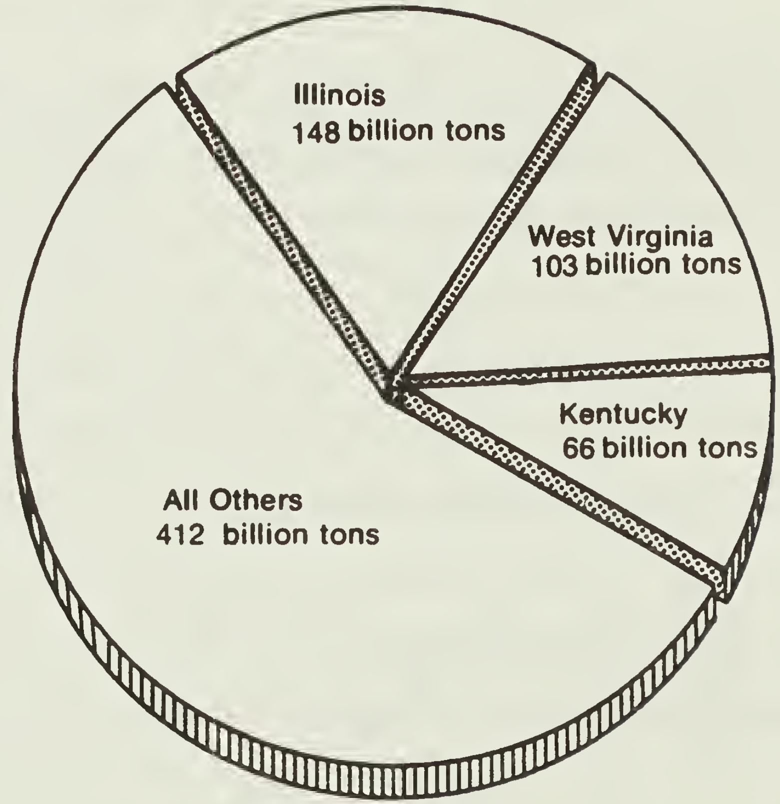


The cost of producing steam has increased at a prodigious rate, due to burgeoning fuel oil prices. During FY-73, the University of Illinois at Urbana-Champaign secured fuel oil under contract at $.1085 per gallon. Fuel oil was budgeted for FY-74 at $.12 per gallon. Because of the federal fuel allocation program, UIUC was forced to pay as much as $.255 to secure an adequate supply of oil. As of July 1974, UIUC was paying a dock price of $.22 per gallon. For FY-75, the price is expected to range from the July 74 low of $.22 to $.2975 per gallon. The projected price for FY-76 ranges from $.2715 to $.318 per gallon. Most knowledgable sources assess these estimates as extremely conservative.

Even if the FY-75 price were to remain stable at $.22, this would represent an increase of $1,850,000 over the cost of the annual supply of 18.5 million gallons at the previous year's contract price of $.12 per gallon.

BITUMINOUS COAL RESERVES

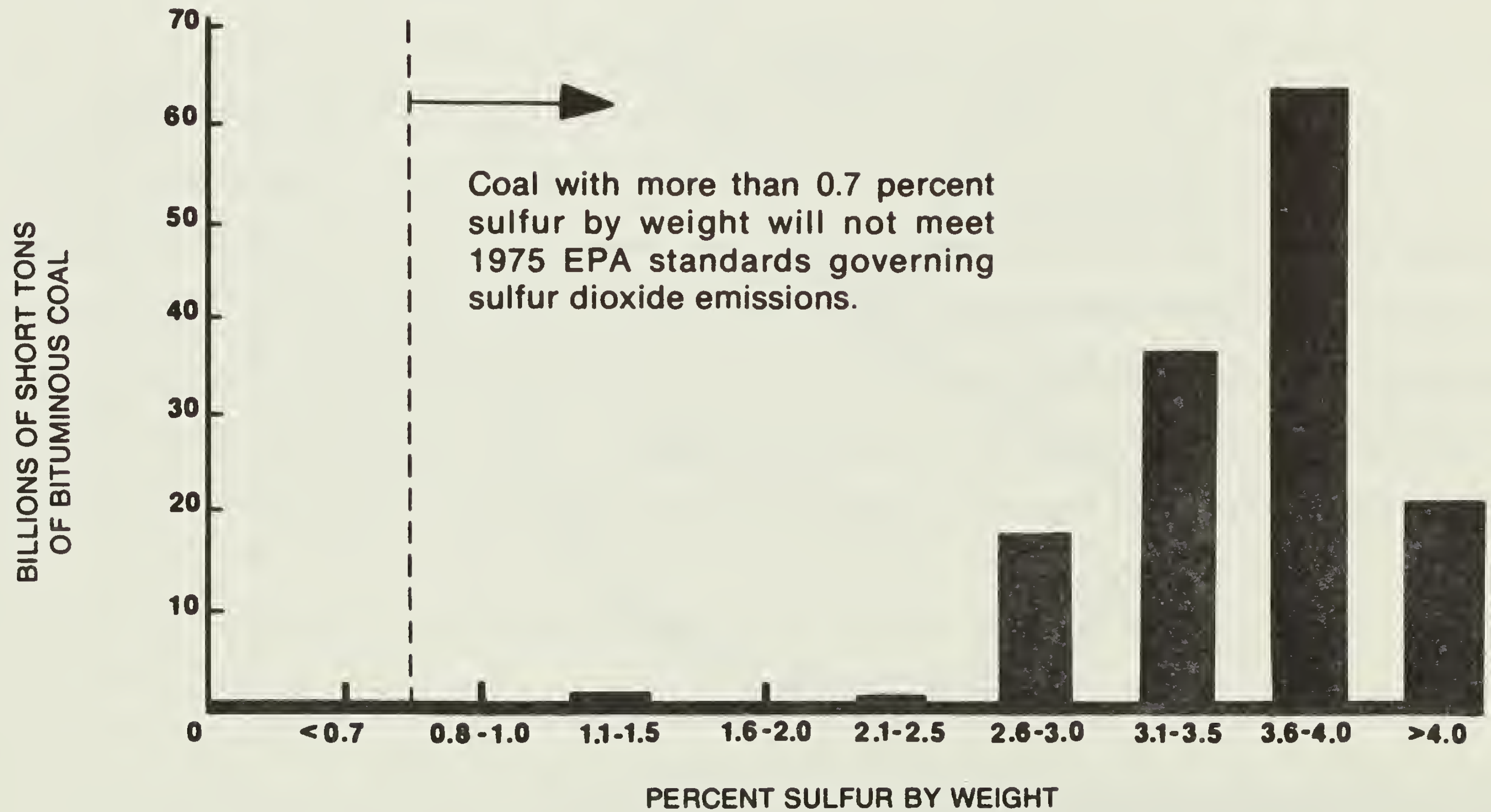
Total U.S. Reserves: 729 billion tons.



- At $20 per ton, the state of Illinois has under its soil a resource valued at $1,500,000,000,000 ($1.5 trillion). (Assuming a 50% recovery rate.)
- Illinois contains one-fifth of America's bituminous coal supply.
- Coal underlies two-thirds of Illinois.

A potential energy source, of enormous value and extent, underlies two-thirds of the state. Illinois has within the confines of its borders, one fifth of the nation's supply of bituminous coal. Including recoverable and marginal reserves, the supply totals 148 billion tons--44 percent more than any other state in the union. To truly grasp the enormity of this resource, consider the following: although coal has been mined in Illinois for more than 100 years, 95 percent of its coal supply still remains. At a rate of $20 per ton, this resource represents a value of 1.5 trillion, assuming a 50 percent recovery rate.

CHARACTERISTICS OF ILLINOIS COAL



- Illinois has 36.5 percent of the nation's high-sulfur (greater than 3.0 percent sulfur by weight) bituminous coal within its boundaries.

Although Illinois has by far the largest bituminous coal reserves of any state, it ranked only fourth in production in 1971, producing only half as much coal as West Virginia or Kentucky and only 80 percent as much as Pennsylvania. This discrepancy can be attributed to the fact that most Illinois coal is high in sulfur. In terms of high-sulfur coal (3.0 percent by weight or more) Illinois has more than one third of the nation's supply, nearly 120 billion tons.

The distinction between high- and low-sulfur coal reserves is vitally important because of 1975 sulfur dioxide pollution control regulations which prohibit the emission of more than 1.2 pounds of sulfur dioxide per million Btu's of heat generated by the burning of coal in new plants. To meet this standard, a coal containing 21 million Btu per ton cannot contain more than 0.7 percent sulfur by weight. All known Illinois bituminous coal reserves exceed this margin.

EXPENSE OF RECONVERSION OF ABBOTT POWER PLANT TO PARTIAL COAL-FIRED OPERATION

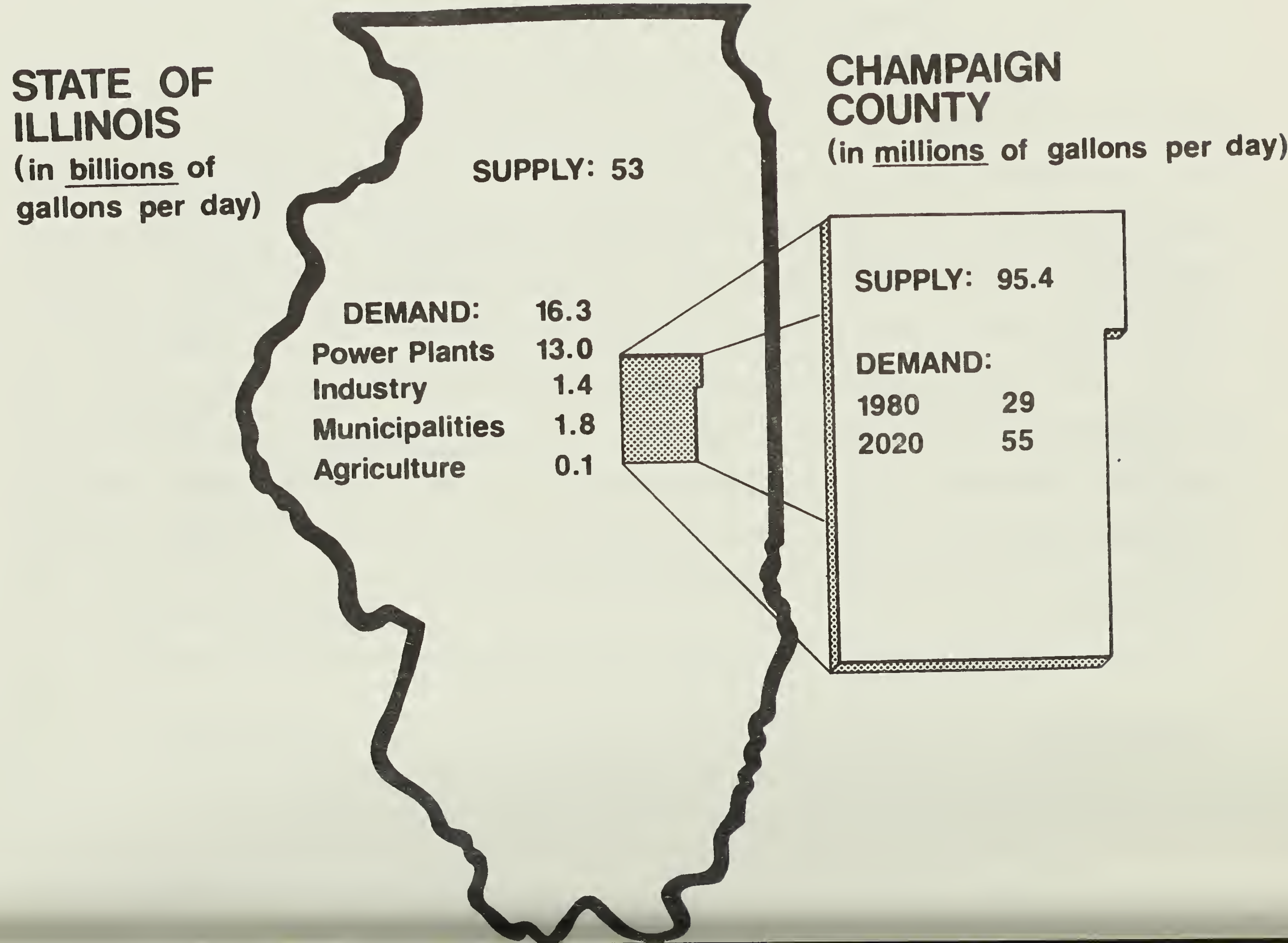
Nonrecurring	
Boiler Conversion	$ 120,000
Precipitator Installation	816,000
Initial Coal Inventory	200,000
Miscellaneous	164,000
Total	$ 1,300,000
Recurring*	
Additional Manpower	$ 120,000
Ash Removal	20,000
Spare Parts	60,000
Total	$ 200,000
Stack Gas Scrubber	$ 9,000,000
Grand Total	$10,500,000

* Does not include cost of coal

Although reconversion to partially coal-fired operation is possible, it is not economically feasible. Only three stoker boilers can be returned to coal firing. Even with these three, the added cost of operation during the first year would total $1.5 million. The major expenses would include installation of a particle precipitator, the cost of boiler conversion, the stock piling of an initial coal supply, additional manpower, ash disposal, and acquisition of spare parts.

The principal obstacle to be overcome in the use of Illinois coal involves its high sulfur content. Desulfurization is usually thought of in terms of stack gas "scrubbing" to remove the sulfur dioxide. An exhaust gas scrubber for Abbott Power Plant would cost approximately $9 million. Further, this is a relatively new process which is, as of yet, still unproven by thorough demonstration. Coal cleaning or liquefaction and solvent extraction, though proven, are equally expensive.

WATER RESOURCES

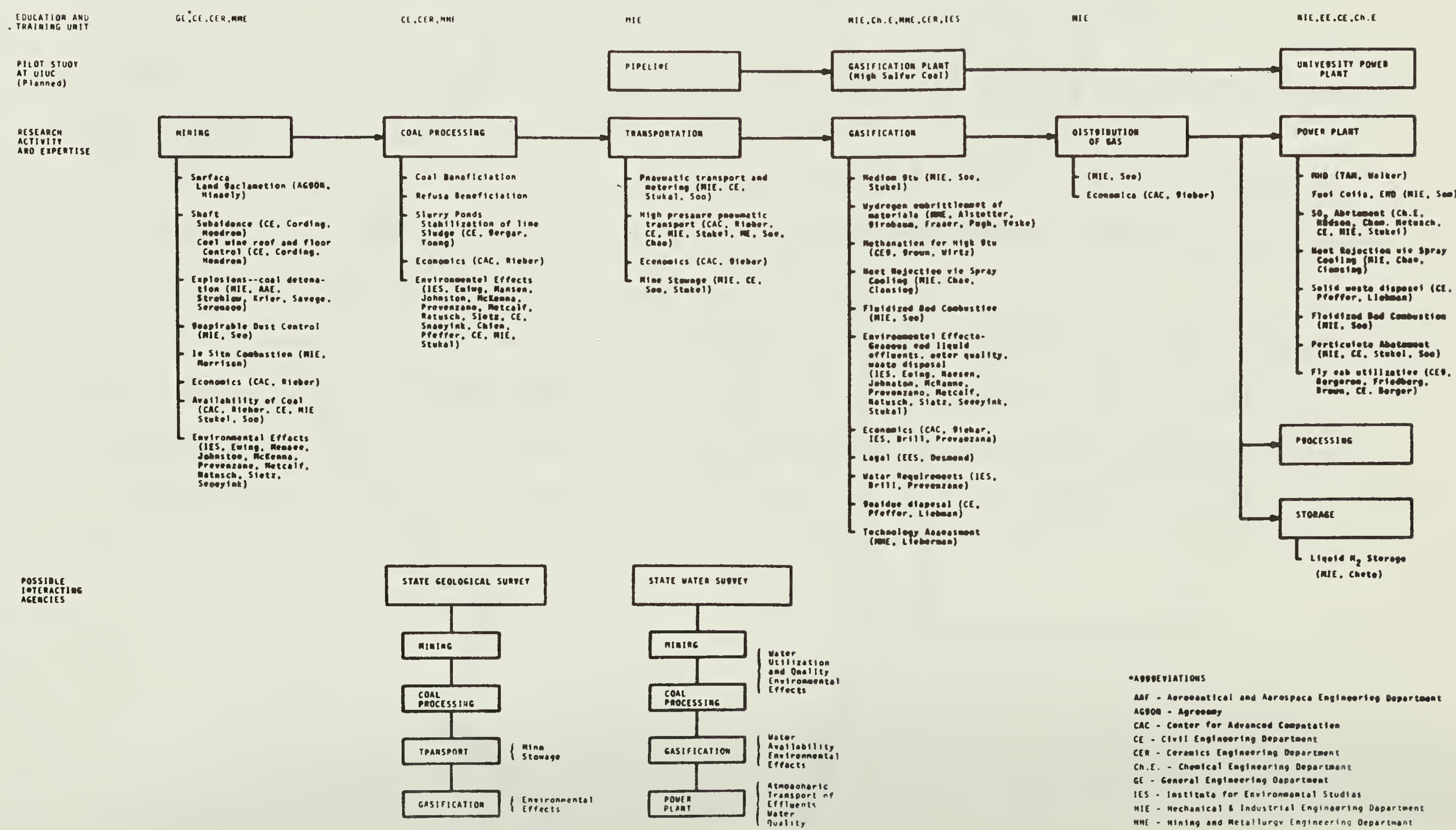


Any consideration of alternative forms of power generation must of necessity include an evaluation of available water resources. Thermal power generation, using 13 billion gallons per day, is the single largest use of water in the state. Other industrial, municipal, and agricultural users account for an additional 3.3 billion gallons per day. Even so, there is a surplus of 36.7 billion gallons per day of supply over use statewide.

Locally, within Champaign County there is also adequate water. According to the recent projections of the Technical Advisory Committee on Water Resources, potential supply will exceed demand in Champaign County by at least 80 percent well into the twenty-first century.

Based on these data, there is ample water for any alternatives which may be considered.

TECHNICAL EXPERTISE AT UIUC

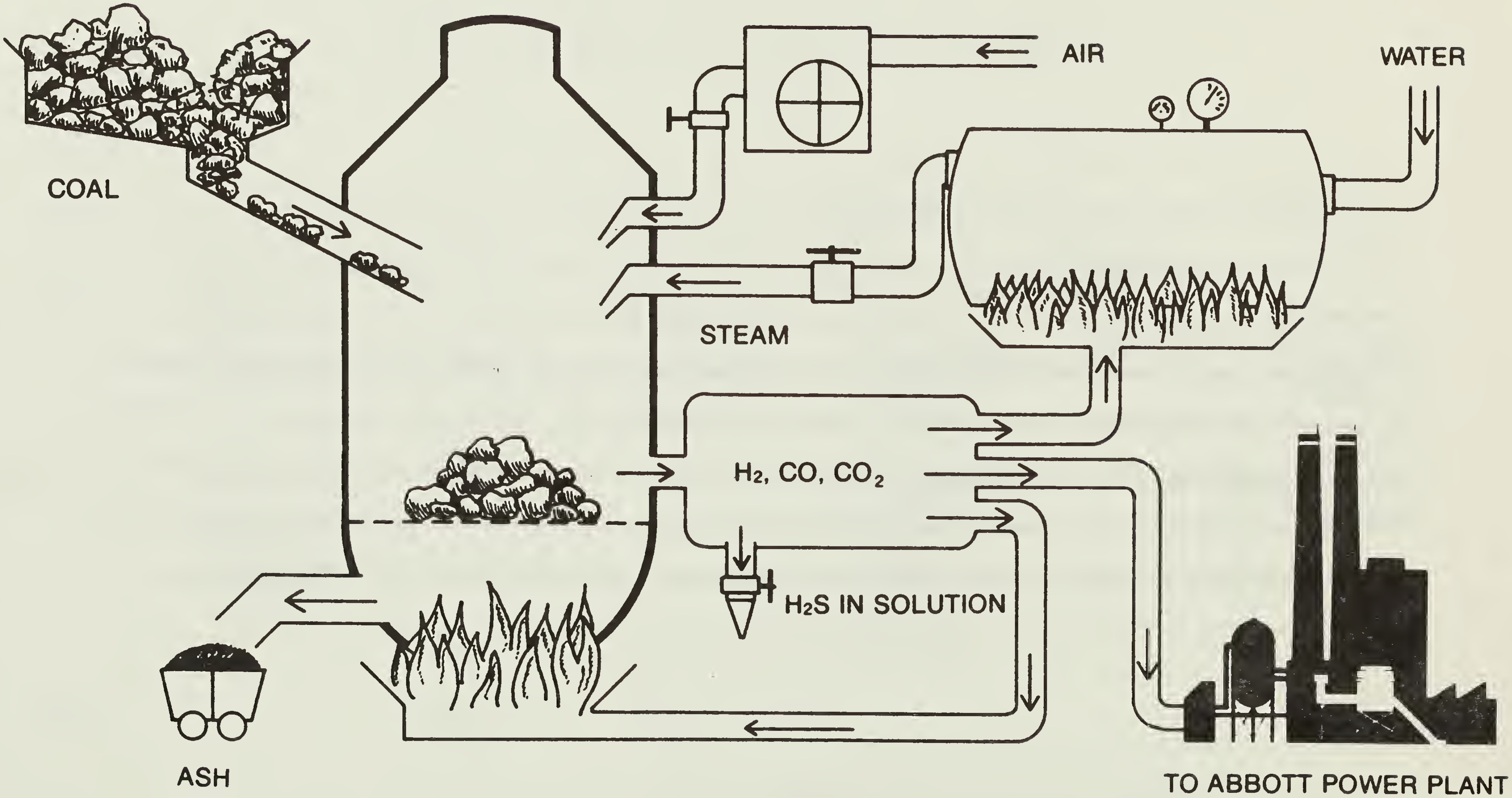


*ABBREVIATIONS

AAE - Aeronautical and Aerospace Engineering Department
AGRON - Agronomy
CAC - Center for Advanced Computation
CE - Civil Engineering Department
CER - Ceramics Engineering Department
Ch.E. - Chemical Engineering Department
GE - General Engineering Department
IES - Institute for Environmental Studies
MIE - Mechanical & Industrial Engineering Department
MME - Mining and Metallurgy Engineering Department

It will be important to marshal human resources to the solution of the Abbott Power Plant fuel problem. The University of Illinois at Urbana-Champaign numbers among its faculty persons with expertise in nearly all areas of coal from exploration to disposal of ash. Broad areas of competence include the exploration, extraction, processing, transport, and gasification of coal; storage and distribution of gasified coal; economics of coal utilization; and power plant operation.

THE GASIFICATION PROCESS



- The product gas is a medium-Btu gas of 340 Btu per cubic foot.
- Natural gas contains 1,000 Btu per cubic foot.

While desulfurization is usually associated with stack gas scrubbing or coal pre-washing, it can also be accomplished during coal gasification. Coal may be gasified into a medium-Btu gas which can be pipelined to the customer. In the gasification process, sulfur is removed and the product gas can meet EPA standards.

The gasification process converts a mixture of steam and coal to hydrogen, carbon monoxide, and carbon dioxide. Steam for the gasification process is produced and heated by burning part of the gas generated. In the process, sulfur in the coal is converted by the steam to hydrogen sulfide and can be removed. The gas produced for the process boiler and for piping into power plant boilers is virtually sulfur-free, medium-Btu gas.

The coal used in this process can be run of the mine. The gas burned in the power plant will cause no significant pollution and will permit more efficient boiler operation at lower stack gas temperatures.

THE CHEMISTRY OF GASIFICATION

$$1 \quad C + H_2O \rightleftharpoons CO + H_2 \qquad (41.91 \text{ kcal/g-mole})$$

$$2 \left\{ \begin{array}{ll} C + 2H_2O \rightleftharpoons CO_2 + 2H_2 & (42.60 \text{ kcal/g-mole}) \\ CO + H_2O \rightleftharpoons H_2 + CO_2 & (.69 \text{ kcal/g-mole}) \end{array} \right.$$

- There is no combustion of the coal; air or oxygen is not required.
- This process uses steam as both a reactant and as a heat transfer medium.
- High pressure condensation of the steam at the end of the process removes sulfur compounds (H_2S, SO_2) and carbon dioxide due to their high solubility.

These are the basic reactions for coal gasification. They account for the fact that carbon (C) from coal reduces steam (H_2O) to carbon monoxide (CO) and hydrogen (H_2) to constitute the fuel gas. The predominancy of reaction (1) or reaction (2) depends on the quenching temperature. Carbon dioxide (CO_2) formed simultaneously will be removed by absorption. The numerals indicate the heat to be furnished for gasification.

OPERATING PARAMETERS

Coal Consumed	550 tons per day
Water	
Converted (consumed)	120 GPM*
Cycled (needs treatment)	620 GPM
For Cooling (recycled)	10,000 GPM
Air	52,000 CFM**
Product Gas	
At low temperature & pressure	15,400 CFM
At high temperature & pressure	22,100 CFM

* GPM is gallons per minute.
** CFM is cubic feet per minute.

The gasification facility, which would be located away from Abbott Power Plant, would convert 500-600 tons of coal daily. Since transferring from oil- to gas-fired operation can be readily accomplished in only a few moments, Abbott Power Plant could operate on gas when it is available, and burn oil when the gasification facility is not producing.

The plant would consume 120 gallons of water per minute. Six hundred twenty gallons per minute will need chemical treatment to remove ash, dissolved hydrogen sulfide, or other residues. Lastly, it would require 10,000 gallons per minute of cooling water. This suggests a cooling tower, a 10-acre sprayer pond, or a 120 acre cooling pond. The product gas will be produced at a rate of 15,000 to 22,000 cubic feet per minute depending on the temperature and pressure of the process.

FUEL COSTS — VARIOUS ALTERNATIVES

To Produce 2.1 Billion Pounds of Steam — Projected FY-75 Usage

		Relative Cost
All Oil Fired — 18,500,000 Gallons Per Year		
At $.22 per gallon	$4,070,000	1.00
At $.30 per gallon	$5,550,000	1.36
At $.35 per gallon	$6,475,000	1.59
Conventional Coal Fired — 125,000 Tons Per Year		
(Stoker coal-cleaned & screened)		
At $20 per ton* (high-sulfur Illinois coal)	$2,500,000	0.61
At $30 per ton* (high-sulfur Illinois coal)	$3,750,000	0.92
At $40 per ton (low-sulfur western coal, delivered)	$5,000,000	1.22
Coal Gasification		
Low Temperature & Pressure — 170,000 Tons Per Year		
At $10 per ton (run of the mine)	$1,700,000	0.42
At $20 per ton (run of the mine)	$3,400,000	0.84
At $23.94 per ton (parity with $.22 oil)	$4,070,000	1.00
High Temperature & Pressure — 120,000 Tons Per Year		
At $10 per ton (run of the mine)	$1,200,000	0.29
At $20 per ton (run of the mine)	$2,400,000	0.58
At $33.92 per ton (parity with $.22 oil)	$4,070,000	1.00

* These cost estimates do not include the installation and operating costs of a stack gas scrubber which would be necessary to burn high-sulfur coal.

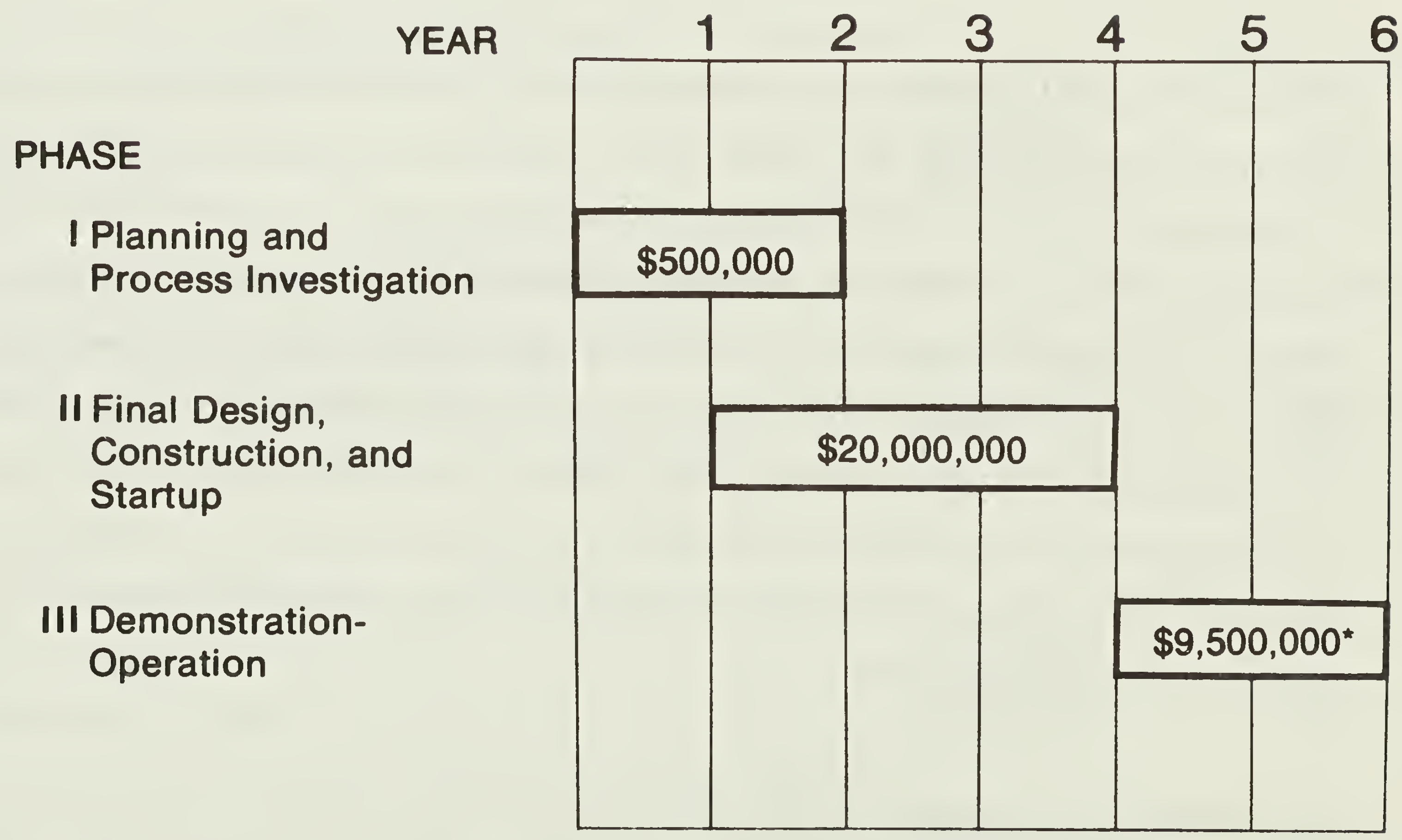
To meet heating and cooling requirements alone (excluding generation of electricity), the University needs to generate approximately 2.1 billion pounds of steam annually. Using No. 2 fuel oil, the annual cost would range from $4.070 million to $6.475 million.

Although the cost of coal is less expensive, conventional high-sulfur coal firing requires installation of a stack gas scrubber, and reconversion to coal-fired operation. If low-sulfur western coal were used to avoid the necessity of a stack gas scrubber, its high purchase and delivery price makes it less competitive. Reconversion costs, precipitator installation, and other increased operating expenses, make low-sulfur western coal even less feasible.

Coal gasification compares favorably with either of the preceeding alternatives. A low-temperature, low-pressure operation gasification facility of 58 percent efficiency would require 170,000 tons of coal annually. However, because of the character of the gasification process, the coal could be low-cost and run of the mine. The price per ton could reach $23.94 before equalling the annual cost of No. 2 oil. This low-temperature, low-pressure process has been demonstrated and an efficiency estimate of 58% is quite conservative.

The high-temperature, high-pressure operation is less certain. If the potential 83 percent efficiency can be achieved, only 120,000 tons of coal would be required. In order to equal the annual cost of No. 2 oil, high-sulfur, run-of-the-mine Illinois coal would have to rise to nearly $34 per ton.

PROJECTED SCHEDULE AND ESTIMATED COSTS



Total $30,000,000

* Includes a two-year supply of coal.

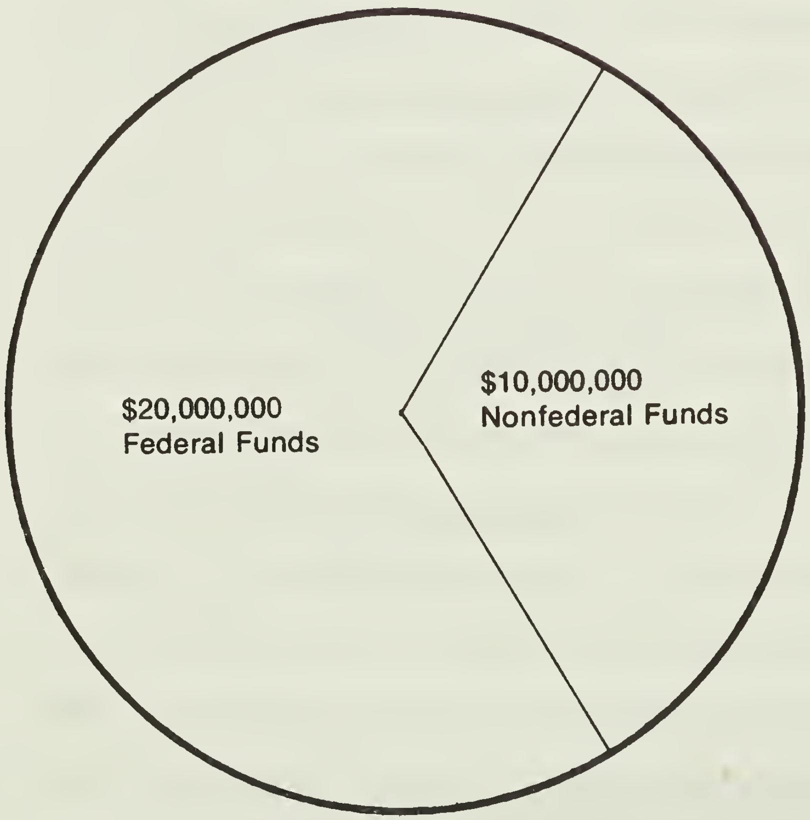
The first phase of the project is largely conducted by University personnel: faculty, research engineers, graduate students, and laboratory support personnel. The first year will provide preliminary design of gasification plant, a set of specifications for the final design and construction of the plant, initial bench model tests for processes, etc. The second year (concurrent with beginning of phase II) will continue the study of processes, operating parameters, engineering and economic analysis, etc.

Activities for this phase II include final (detail) design, bidding and actual construction of plant, start-up experiments for initial (experimental) runs, etc. Work and dollars are largely contracted for with outside agencies -- consulting engineers and contractors working with the University team.

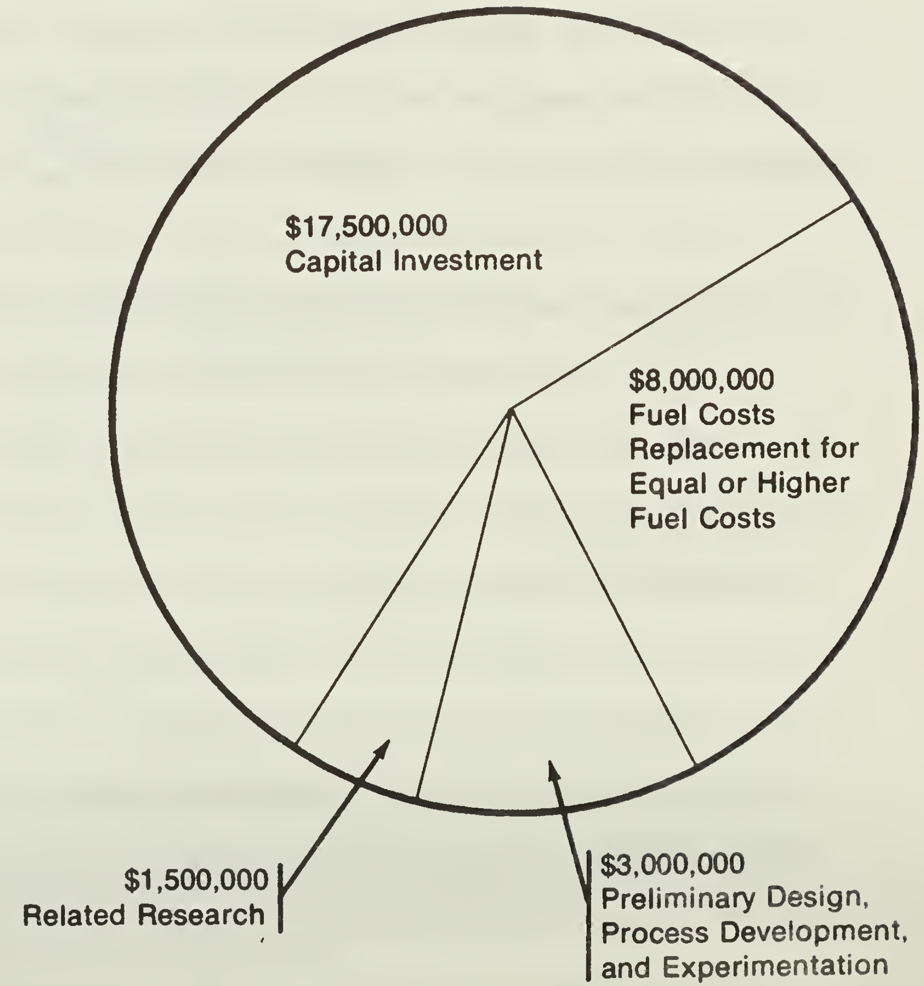
Phase III, a two-year demonstration period, will consist of operating over various parameters of reaction temperatures, boiler pressures, types of coal, water treatment, effluent analyses and other plant operating variables and characteristics. Cost of this phase includes estimated cost of fuel (coal) for a two-year period ($8,000,000) for efficiencies ranging from 58% (at low temperature and pressure) to 83% (for high pressure and temperature) and coal prices ranging from $10 to $30 per ton. The cost also includes $1,500,000 for two years of operation including regular plant operating staff as well as an experimental group which will be monitoring and adjusting plant operating variables. This experimental group will also be responsible for design and development of operating manuals, plant operating charts, experimental run characteristics, etc.

PROPOSED SOURCES AND EXPENDITURES OF FUNDS

Sources: $30,000,000



Expenditures: $30,000,000



The tentative budget for the coal gasification project calls for $30 million. Two-thirds of this amount would be derived from federal sources. chiefly the Office of Coal Research on a matching basis. One-third must be from nonfederal sources.

Expenditures for the project break down as follows. The largest single expenditure is a $17.5 million capital investment for the construction of the plant. Following the demonstration period, the gasification facility will be available for continuous operation in the University's power plant system.

An additional $8,000,000 will be used to obtain various types, grades, and qualities of coal for the two-year demonstration-operation phase. Since the facility will be providing gas to Abbott Power Plant during this phase, this cost represents a replacement of equal or higher fuel oil costs to the plant during the same period.

Preliminary design, process development, and experimentation are budgeted for $3 million. Much of this work will be contracted with outside agencies -- consulting engineers and contractors working with the University.

Related research on the development of the facility is budgeted for $1.5 million. This research, which is ongoing through all six years of the project, includes benchmodel tests for processes, start-up experiments, and monitoring and adjusting plant variables during the final phase of the project. This work will be largely accomplished by University personnel: faculty, research engineers, graduate students, and laboratory support personnel.

PAYOUT PERIOD FOR UNIVERSITY OF ILLINOIS THROUGH FUEL SAVINGS AT ABBOTT POWER PLANT

Cost of producing one million Btu(MBtu) by burning oil (82% efficiency, \$.22 per gallon, 138,500 Btu/gallon).	\$1.937
Cost of producing one MBtu by gasification of high-sulfur coal, low temperature and pressure (52.2% efficiency, \$10.94 per ton, 24 MBtu per ton).	\$.873
Cost of producing one MBtu by gasification of high-sulfur coal, high temperature and pressure (74.7% efficiency, \$10.94 per ton, 24 MBtu per ton):	\$.611

Annual Cost Differentials	
Oil vs low-temperature gasification	\$2,234,400
Payout period to recover \$10 million	4.5 years
Oil vs high-temperature gasification	\$2,784,600
Payout period to recover \$10 million	3.6 years

One of the major considerations for capital projects is the length of time to recover the initial outlay: the payout period. One method of recovering the outlay is through reduced fuel costs at Abbott Power Plant.

Abbott Power Plant requires 2.1 million MBtu (million Btu) to produce the required amount of steam annually.

Heat produced by burning No. 2 fuel oil at $.22 per gallon costs $1.937 per MBtu. Heat produced by burning gasified coal costs $.873 per MBtu (for the low-temperature process) or $.611 per MBtu (for the high-temperature process).

The annual cost differential between oil and the two gasification processes are the product of the difference in cost per MBtu and the number of MBtu required. The payout period represents the number of years of this differential necessary to recover the initial nonfederal investment of $10 million. For the low-temperature gasification process, this is 4.5 years; for the high-temperature process, it is 3.6 years.

PAYOUT PERIOD FOR STATE OF ILLINOIS THROUGH INCREASED RETAILER'S OCCUPATION TAXES

Sales of high-sulfur coal to industrial and commercial markets within Illinois.	
1966	11,002,000 tons
1973	– 5,195,000 tons
Total Decline (Annual)	5,807,000 tons
Assume that half this market can be reclaimed via coal gasification, annually	2,903,500 tons
Value of above at $10.94 per ton	$31,764,290
State & local taxes at 5% of half of this amount. (Sales to state institutions are tax exempt)	$794,107
Payout period to recover $10 million	12.6 years

The State of Illinois is entitled to a return on its investment in a coal gasification facility. One dimension of this return may be seen by examining the tax system. According to the Department of Revenue, a retailer's occupation tax on the value of the coal accrues to sales to customers within Illinois, unless specifically exempt.

Since 1966 (prior to air pollution control regulation but after the inroads of oil and natural gas) the amount of coal sold within Illinois to industrial and commercial markets has declined more than 50 percent from 11 million tons to 5.2 million tons annually. If the gasification demonstration is successful, perhaps half of this market loss of 5.8 million tons can be recovered via gasification. At $10.94 per ton for high-sulfur run of the mine coal, this has a value of $31.7 million.

Since sales to state institutions and agencies are tax exempt, assume only half of this amount is subject to retailer's occupation tax of 5 percent. This amounts to $794,000 per year in revenue to the state. In 12.6 years, the state will recover the initial $10 million.

STATE INSTITUTIONS WHICH COULD POTENTIALLY USE GASIFICATION

- There are 25 other state institutions with power plants at which gasification might be feasible.
  - 6 universities
  - 6 correctional institutions
  - 13 mental health facilities

M - Mental health facilities

U - Universities

C - Correctional institutions

Twenty-five power plants, similar to Abbott, but smaller, are operated by state institutions: six by state-supported universities, six by correctional institutions, and thirteen by the Department of Mental Health. These plants either burned coal directly (which will be effectively prohibited in 1975) or natural gas (which is becoming both scarce and expensive). Small gasification facilities appear to be an ideal solution to their fuel problems which closely parallel those of Abbott Power Plant. Power plants of this size represent a substantial market for Illinois coal.

GASIFICATION ADVANTAGES

- Savings in fuel cost.
- Avoids reconversion cost and downtime.
- Meets all applicable EPA standards.
- Uses Illinois coal.
- Provides Abbott Power Plant with alternate fuel sources.

First, and foremost, gasification will provide substantially reduced fuel costs as shown. Gasification also obviates the necessity for the estimated $10.5 million cost of partially reconverting to coal-fired operation and installing stack gas scrubbers as required to meet EPA standards. Economical Illinois high-sulfur coal can be used, and Abbott's oil-burning capacity serves as a backup system to the gasification system.

BENEFITS TO THE STATE OF ILLINOIS

- Provides a market for Illinois high-sulfur coal.
- Solves UIUC power problem.
- Serves as demonstration plant for 25 other state institution's power plants and also for various state industrial power plants.
- Illinois' contribution to the solution of the energy crisis.

If the University of Illinois can demonstrate an economically feasible means of converting high-sulfur Illinois coal into a "clean" fuel, the impact on the State of Illinois and the nation would be profound. Expansion of the Illinois coal industry would affect all of southern Illinois. Demonstrated gasification would virtually convert an otherwise unused resource into a vast reservoir of energy for the state, the midwest, and the nation. Successful demonstration of gasification would be a vital contribution to Project Independence, to make the U.S. more self-reliant for its energy demands.

Many Illinois industries operate their own power plants which are roughly the same size as Abbott. They are caught in the same economic-regulatory squeeze as Abbott. Just as a gasification facility serves as a demonstration plant for state-supported institutions, so can it also serve as a model for Illinois industry.

With the potential savings to be gained through expansion of the Illinois coal industry, more economical operation of its own power plants, and the demonstration of a model plant for Illinois industry, the state will hopefully be an enthusiastic participant in this proposal.

October 17, 1974
Compiled by the Engineering Publications Office

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